U.S. Department of Energy
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Federal Energy Management Program

Welcome to the Energy Markets/ Utility Restructuring Workshop

Pacific Northwest National Laboratory
Operated by Battelle for the U.S. Department of Energy

Your Instructor

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Housekeeping Issues

- *Workshop Time*
- *Breaks*
- *Questions and Answers*
- *Your Expectations*
- http://pnnl-utilityrestructuring.pnl.gov

Workshop Goals

Upon completing this workshop, participants will:

- *Know how to plan for future energy supply and energy use options.*
- *Understand how utilities work and the impact of restructuring on them.*
- *Be aware of options available for buying power in restructured markets.*

Course Outline

- The Basics
  - Utilities
  - Transmission
  - Energy Economics 101
  - Oil Supply and Prices
  - Gas Supply and Prices
- Deregulation/Re-regulation
  - Electricity Market Restructuring
  - Renewable Portfolio Standards
  - State-by-State Review
  - Key PJM Issues

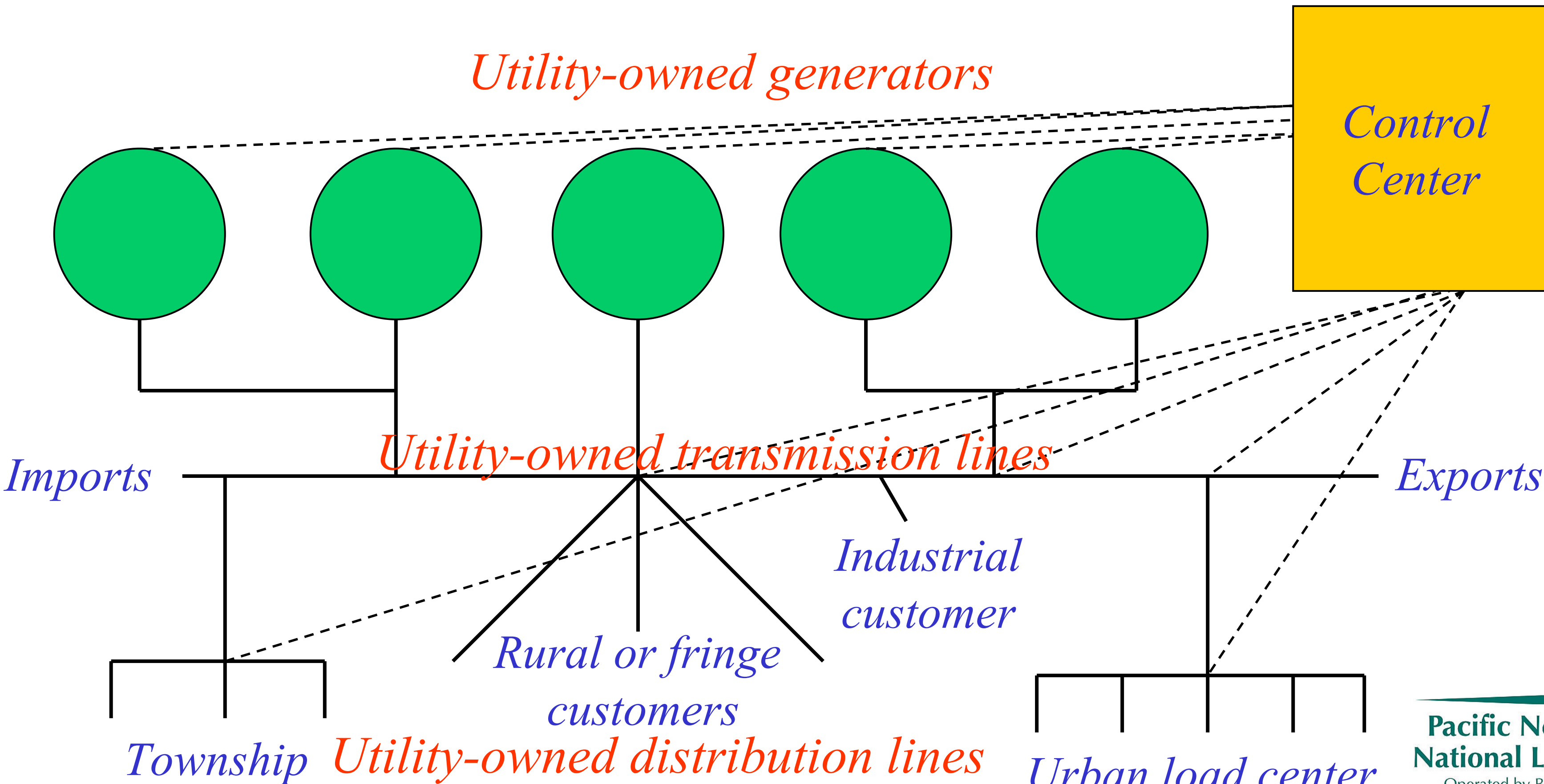
The Basics

- Utilities
- Transmission
- Energy Economics 101
- Oil and Gas Supplies and Prices

Utilities 101

- What they are
- How they plan
- How it all is changing

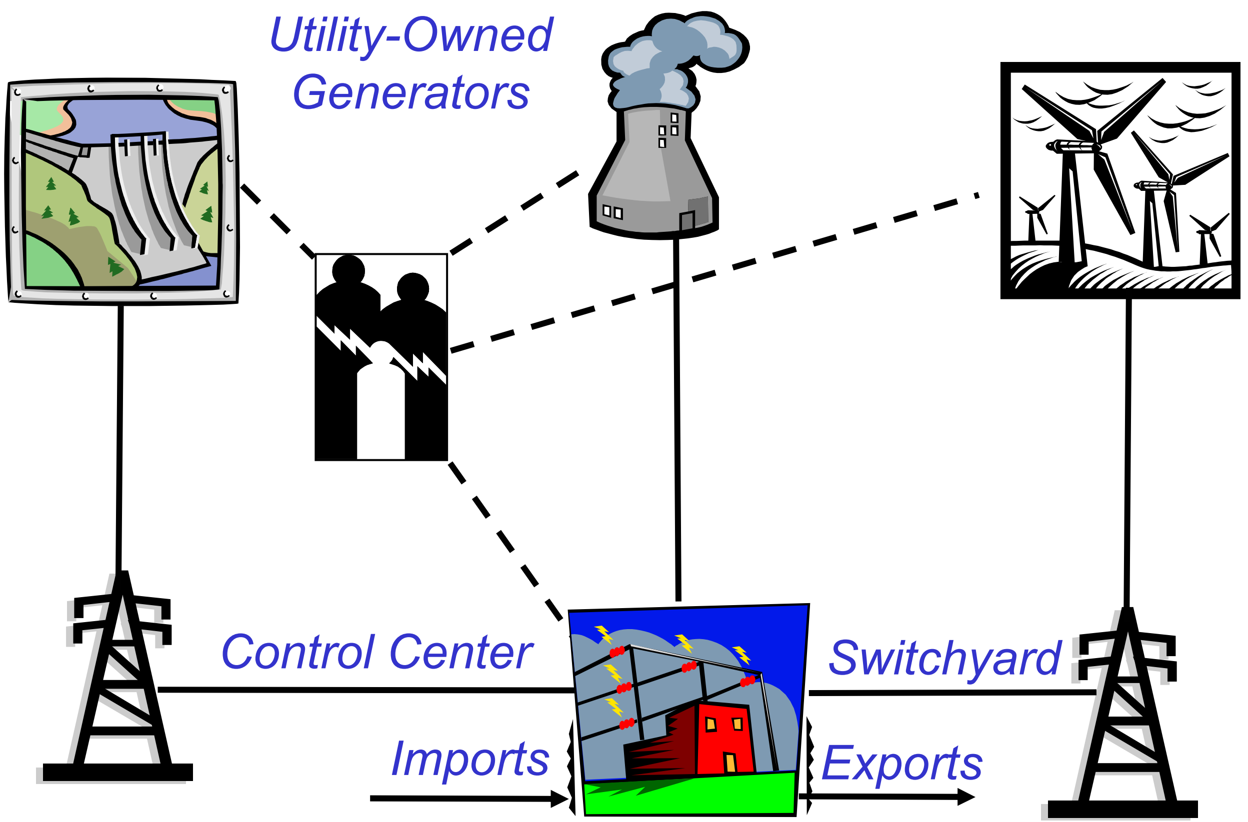
Traditional Vertically Integrated Utility



Vertically Integrated Utility - Archetype

- Bulk Power Generation (production)
- Bulk Power Transmission (truck/rail delivery)
- Local Distribution (delivery)
- Customer Service (marketing, metering, billing, efficiency, etc.)

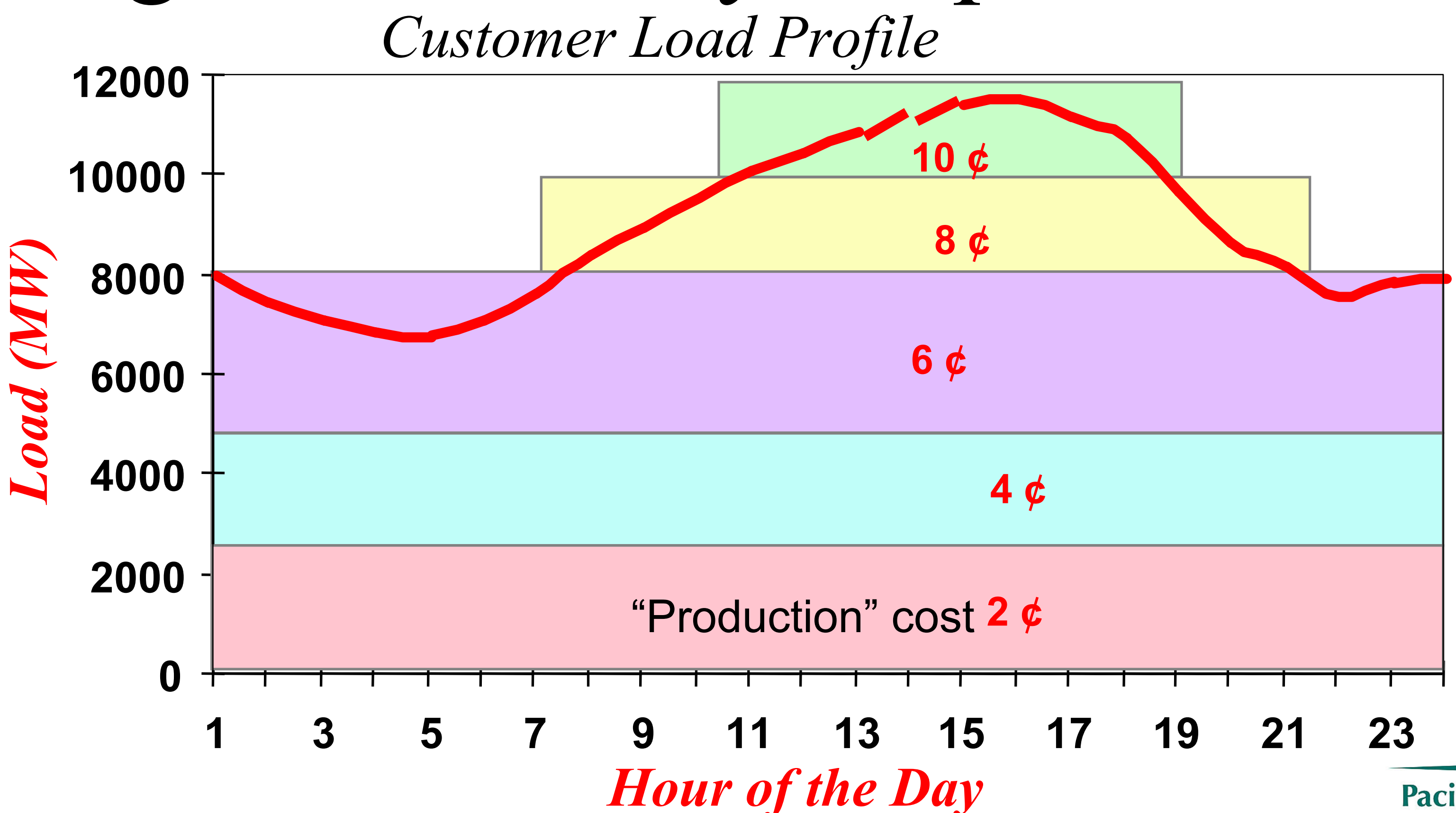
The Bulk Power System



Utility Generation Fleets

- Baseload plants operate almost all the time because they use low cost fuel and are more efficient at full load
  - Typically coal or nuke
- Peakers operate less than 1,000 hours/year because fuel costs are high
  - Also, can cycle on and off and are efficient under low load conditions
  - Typically oil or gas fired simple-cycle combustion turbines
- "Mid-merit" plants operate on shoulder periods so they can cycle up and down gradually
  - They are efficient but may use high-cost fuels
  - Sometimes mid-merit plants are older, smaller baseload plants

Regulated Utility Dispatch



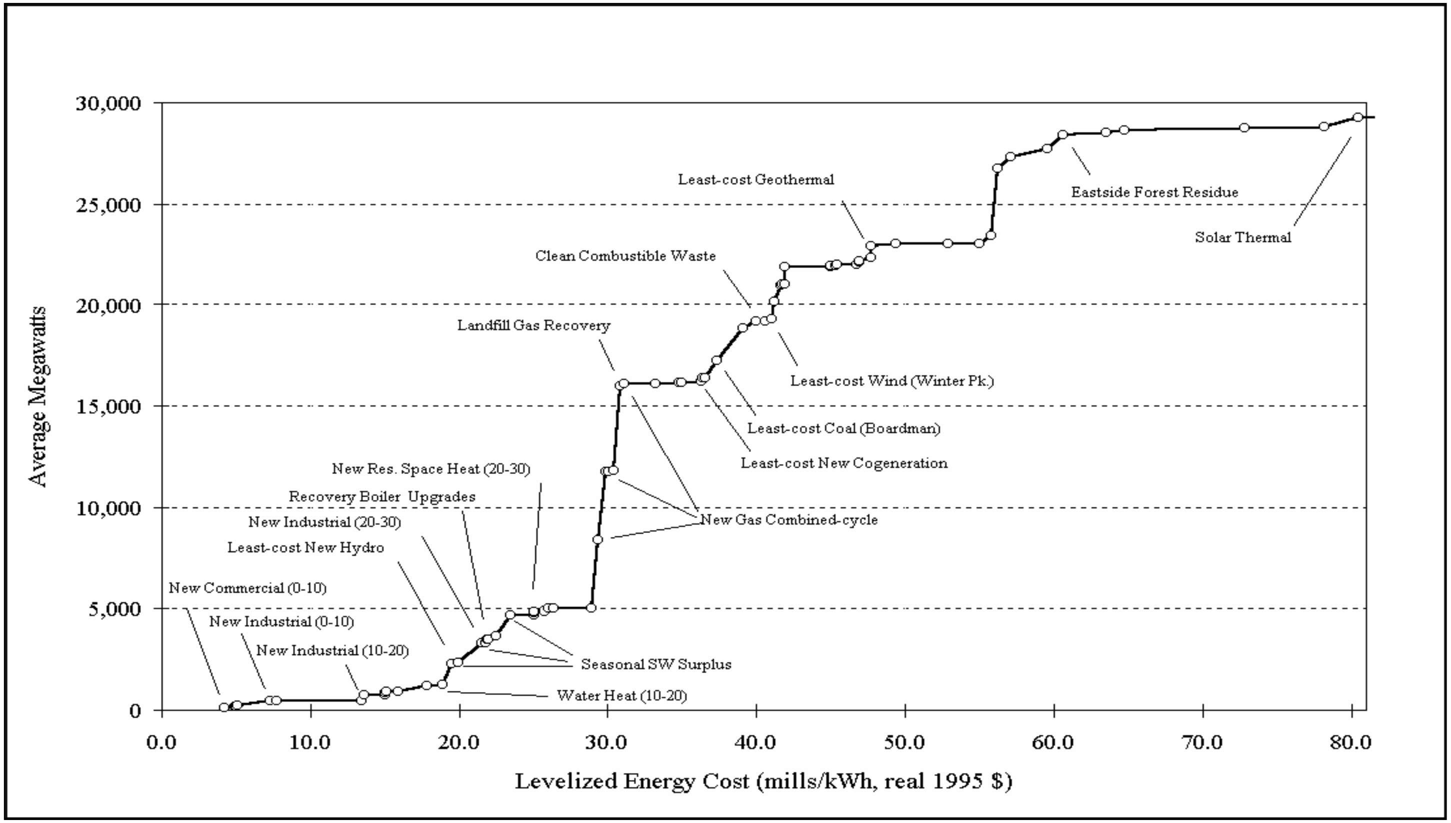
Traditional Utility Generator Economics

- Capital is raised from stockholders and/or bonded debt. Stockholders earn a rate-of-return (ROR) for their investment = profit.
- Interest and operating costs are expense items passed directly to ratepayers.
- Plants are scheduled in "merit order" based on operating costs, lowest first. Capital costs are treated as sunk.
- Some plants are dispatched out of order for efficiency reasons (baseload plants) or "system" (usually means transmission) stability and reliability "must-run."
- Some plants are held in reserve for emergencies, reserve margins ~ 15%.

System Planning 101

- Forecast future demand
- Array existing resources from low-to-high *production* cost to create "supply curve"
- Evaluate new resources (using *levelized* cost supply curve – next slide)
- Assess potential risks (fuel cost and supply)
- Select "optimal" mix of resources

Sample New Resource Supply Curve
(includes capital costs unlike production cost curve)



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Modern Power Supply Economics

- Imports are an important part of power supply because reserves can be shared and used for production when not needed.
- Imports can be used to cover plant outages (key for nuke repairs) and for economy exchanges.
- Exports can reduce rates.
- But, interchanges stress transmission, making utilities more interdependent and reliability more important.

Modern Utility System Planning

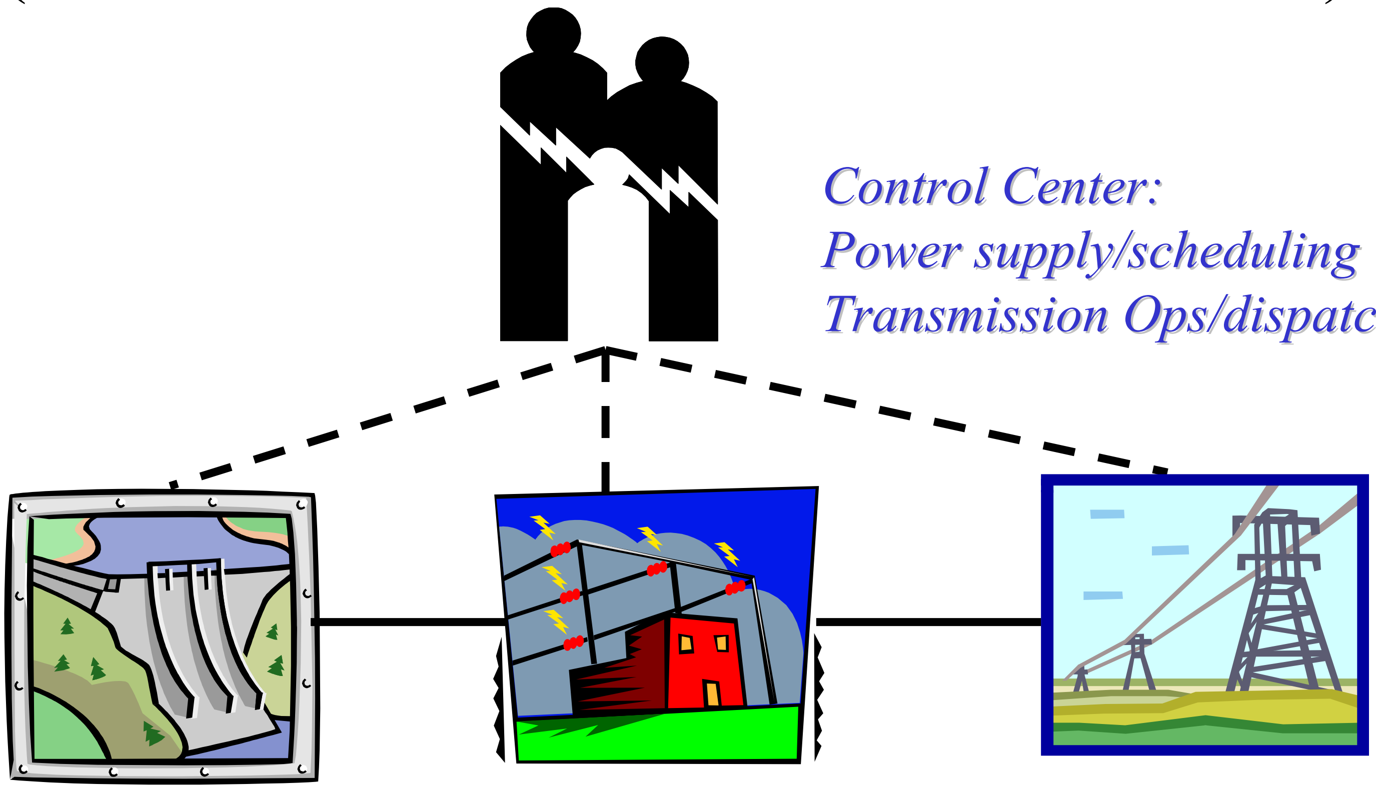
- Assumes regulators won't approve *new power plants* or *long-term bi-lateral* power contracts (even in regulated states).
  - No "reward" for risk taking
  - Too many opportunities for second guessing (especially if utility serves multiple states)
- Assumes adequate resources can be purchased "in the market" on short-term contracts, spot markets, etc.

Modern Power Supply Operations

- Daily operations start with:
  - Load forecast
  - Weather forecast
  - ➲ Generator status report
  - ➲ Transmission outage report
- Generation operating costs are a given.
- Power trades are made (by phone & internet) to:
  - Acquire sufficient power (and reserves)
  - Displace expensive power
  - Make money
- Once trades have been made, transmission is secured for imports/exports.
- Transmission reservations made on OASIS.
- Once all pieces are in place, system is re-scheduled (order and duration of generation changed).

System (Transmission) Operations

(Generation and transmission are substitutes)



Control Center:
Power supply/scheduling
Transmission Ops/dispatch

System Operators/Dispatchers

- Schedule transmission outages.
- Given power supply schedule, execute plant (and transmission) dispatch in real-time:
  - Make sure plant operators can execute schedule
  - Modify plant operations to conform with actual demand
  - Monitor power flow and system status to maintain system parameters (voltage, harmonics, etc.)
- Execute curtailment plan in emergencies.

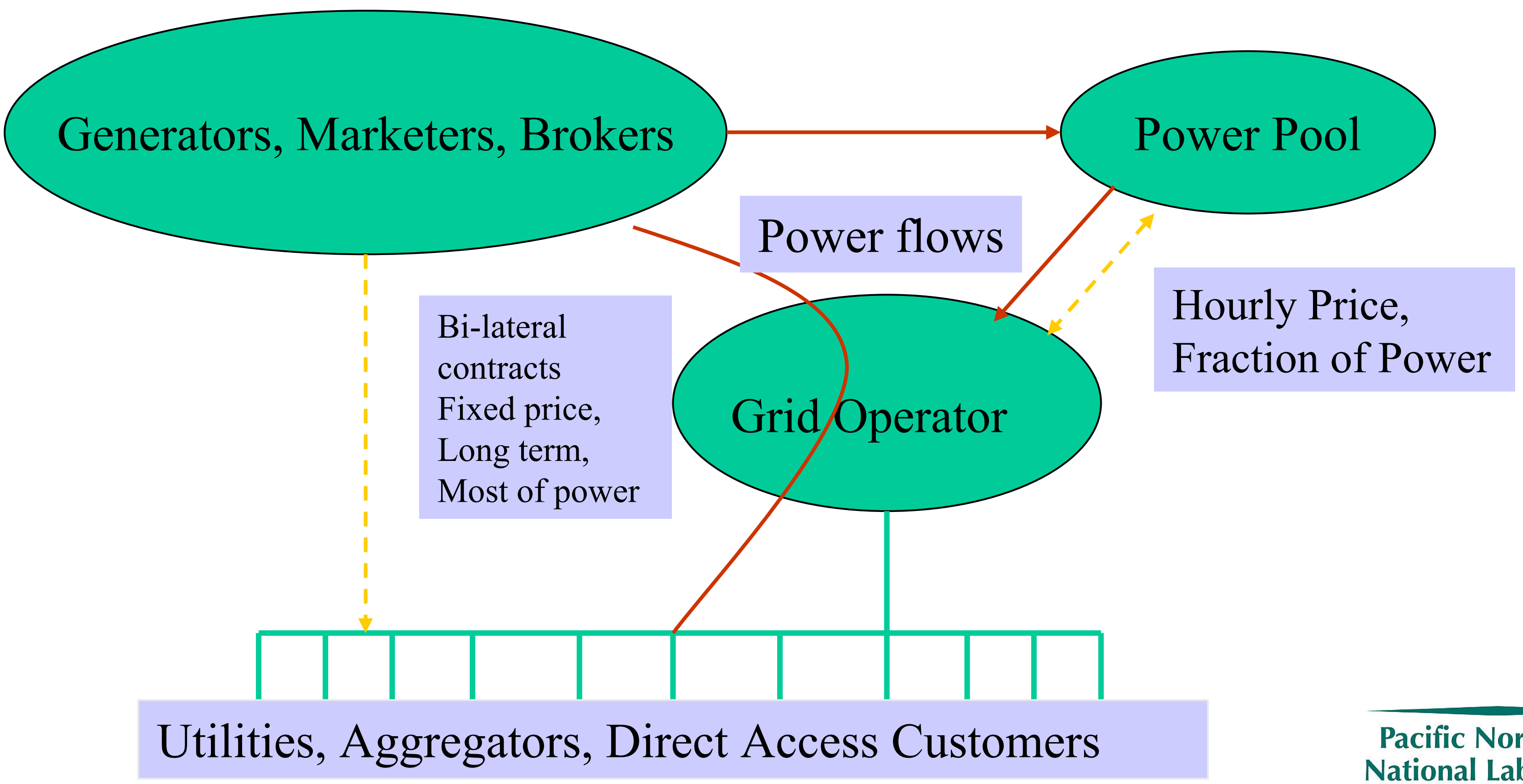
Modern Transmission Operations

- Transmission staff and Generation staff not allowed to talk, physically separated.
- All transactions conducted over the OASIS, including reservations for native load.
- Tariffs conform to Order 888, but unique to utility.
- Planning for utility needs only, not regional market needs.
- System operators may have demand relief program to help manage the grid.

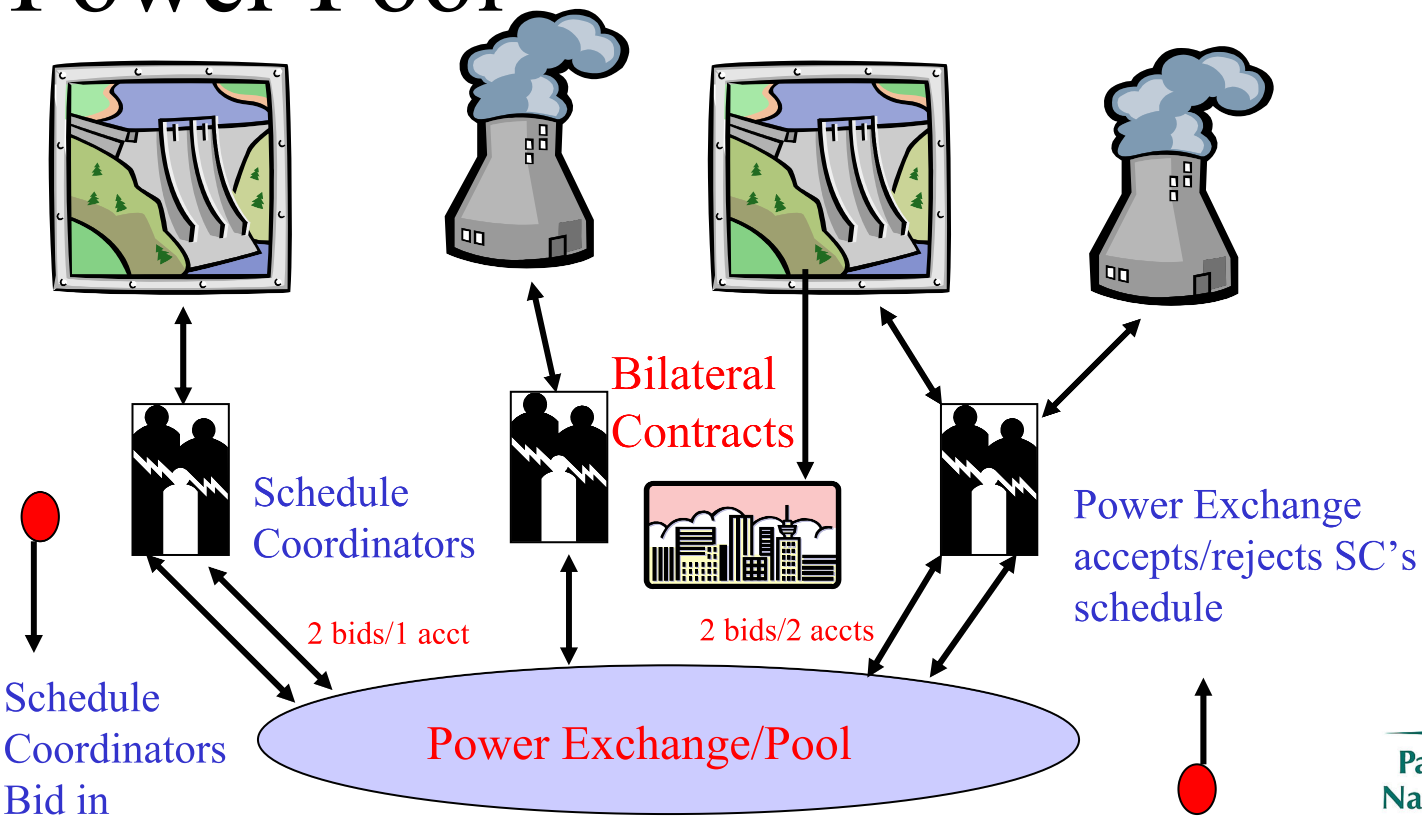
Modern Distribution Operations

- Power mostly flows "down" from transmission lines to customer loads.
- Some customers may have own generation.
- Utility or system operator may have demand relief program to manage loads.
- There is little, if any, interactivity between supply and loads (price or other basis).

New Market Structure: Most of US



Restructured Generation Market w/Power Pool



Plant Scheduling via Power Pool

- Need established by ISO forecast plus reserves. Need reduced by bilateral contracts and must-run generation schedules (or those bids = 0).
- SCs submit bids into energy (kWh) market (markets are mutually exclusive).
- Exchange (pool) accepts/rejects bids based on price (lowest accepted first) until need is met.
- Last accepted bid sets price (MCP). MCP paid to all winners irrespective of initial bid.
- Accepted bids establish schedule (or portfolio bid resubmitted as a schedule).

Power Auction Process

12.5 GW of need from 4 bidders. MCP set by last bid of 2 cents. All Winners get 2 cents, losers get 0. Losers can bid into next auction. Winner has to designate plants.

4,000 MW @ 3

3,000 MW @ 2.5

4,000 MW @ 2

2,500 MW @ 1.5

3,000 MW @ 1

5,000 MW @ 0

Bid Stack: Hour 0600

2,000 MW

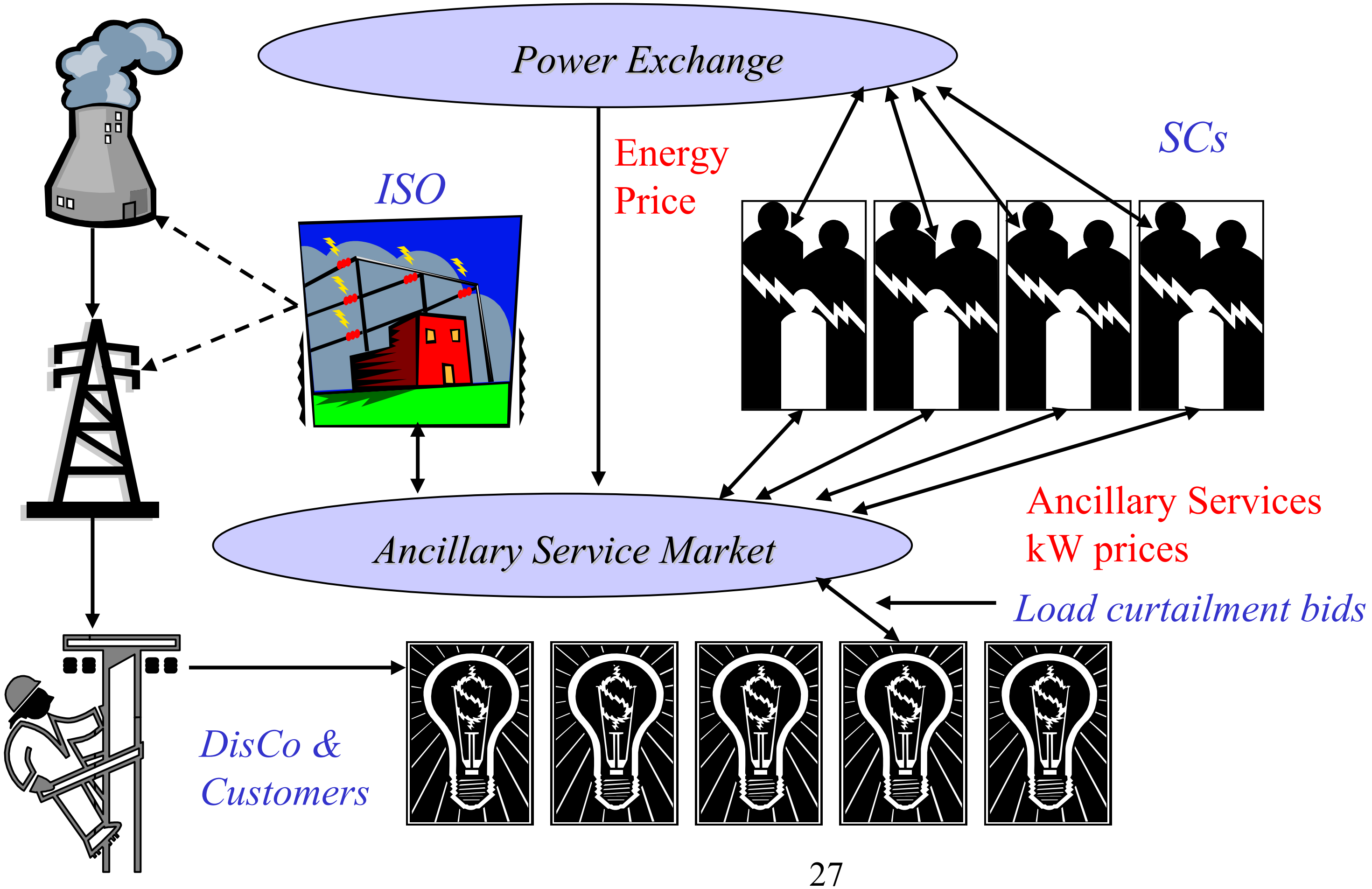
2,500 MW

3,000 MW

5,000 MW

Winners

Restructured Dispatch



Restructured Generation Dispatch

- ISO reviews and establishes final schedule.
- Plants paid to redispatch based on bids (or SCs redispatch).
  - Plants redispatched for economy
  - To serve Load Islands
  - To relieve constraints
  - For reliability
  - To accommodate "wheel through" transactions, parallel path and loop flow, etc.

Transmission

- Competitive transmission services
- Deregulation status
- Blackout/Fallout

The US Transmission Grid

- The world's largest (and probably most complicated) machine – operates at speed of light
- Reaction time typically 3 "cycles" (3/60ths of a second)
- Overall reliability in excess of 99.9% or 8 hours of outage/user (closer to 99.99% - 99.999% in large utilities, 52 – 5 minutes)
- Key aspects have to be in-synch all the time, such as frequency (60 cycles) and phase angle (VARS)
- Because the transmission system "integrated" generation and load, maintaining system stability and reliability is a "transmission" responsibility, although it is mostly done through use of generation (reliability, or "spinning" reserves)

How Transmission Used to Work

- Utility staked claim to transmission it owns for its own use (native load)
- May offer (or not) "spare" capacity to others to use
- Constraints relieved through load curtailments (customer interruptions)
- New lines built by utility as needed and paid for by rate payers
- Utility operated its generation and transmission itself, but in coordination with neighbors. Some utilities transferred operations to other entities (utilities or power pools).

How Transmission Works Now

- Wholesale buyers purchase power from regional seller
- Power wheeled to regional customers over a regional (not "utility) transmission grid by the RTO.
- Buyer arranges for transmission (reservation, and/or right)
- If constraint occurs transmitter (owner/ISO/RTO) will re-dispatch higher cost generation (or purchase demand relief)
- Costs born by seller or transmitter (depending on kind of transmission purchased – reservation vs right)
- Buyer may choose to curtail instead

How Orders 888, 889, 2000 and SMD Changed Transmission

- Utility can reserve capacity and must offer rest to others (limited to "native load")
- All utilities can use remaining capacity on equal footing with owner (ownership has no rights)
- Rates follow similar design across utilities, (but not set at same level)
- Constraints must be "managed," using markets not unilateral processes
- System expansion costs borne by user, may be "socialized" – hence, no significant expansion

Current Trends *(FERC Order 2000 and SMD)*

- Native load reservation under attack
- Constraint management must be "market based" and Demand Relief an option
- Scope of transmission systems growing (geographically)
- Nature of transmission business (not RTO) changing (for-profit vs non-profit)
- System expansion still stagnant

FERC Facing Challenges

- NW and SE utilities opposing FERC vision (through Congress)
- Focus is on "Standard Market Design" rather than standard transmission ownership/operation model (RTO)
- Movement to any "standard" has slowed
- Transmission constraints still a problem outside RTO areas (RTOs seem to work!).

Transmission Issues

- Competitive markets make more and different use of existing transmission system
  - More "through and out" merchant transactions
  - More "network" transactions.
- Different uses of system and different market opportunities result in more constraints, but not always in same places.
- No one wants to pay for "merchant" transmission (even if you could define it).
- Absence of merchant capacity will limit growth of competitive markets and renewable industry.
  - Can't get long term firm transmission access for long term power contracts (only owners can absorb risk of LT transactions)
  - Need new transmission in remote areas for renewable access

Transmission "Solutions"

- New transmission takes ~7-8 years to build, thus, problems won't get fixed overnight (Federal roles?)
- Transmission constraints create "new" market for "congestion relief" and another charge on your utility bill
- Congestion can be relieved through demand relief (customer load reduction for a fee) or using local generation at higher cost (the basis for the congestion fee)
- Transmission siting challenges leading to "non-construction" options – efficiency and DER investments at customer sites – that may limit future "economy" transactions.

Blackout

- Blackout "caused" by what should have been routine (but avoidable) tree-to-line short circuit.
- Outage cause wasn't apparent to utility operator, 1st Energy (MISO RTO not a control center)
- As outage spread, utility operators could not "see" what was happening and didn't know how to respond
- As outage spread to adjacent utilities that *could see*, they took evasive action
- Other utilities depending on 1st Energy/MISO for information got stuck holding the bag
- "Murphy's Law" took effect and key components didn't work as designed.

Fallout

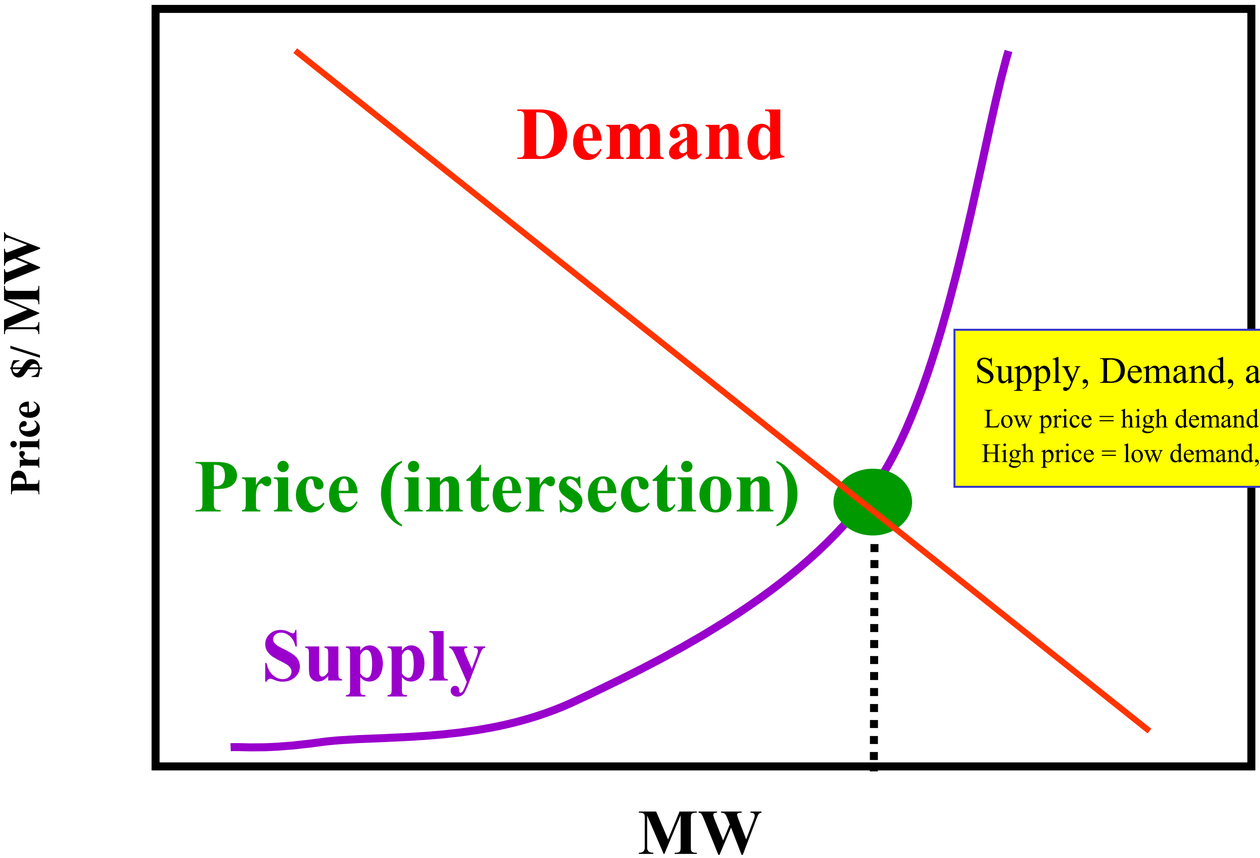
- Tree trimming stepped up
- RTOs will have to be control centers
- More sensors will be installed to improve "vision" along with better control systems
- Reliability coordinators will be given more authority
- Reliability councils will have mandatory standards with penalties

Observations from Blackout

- MISO dominated by large plants (like many other systems)
- Once a large plant trips off-line, it takes several hours (for coal) or days (for nukes) to get back on-line
- Regions with lots of merchant transactions need to have better networks of sensors, controls, and control systems/RTOs. (Deregulation wasn't the problem, lack of control was.)
- Greater plant diversity (including renewables) and more customer control capability would help prevent outages and speed service restoration

Energy Economics 101

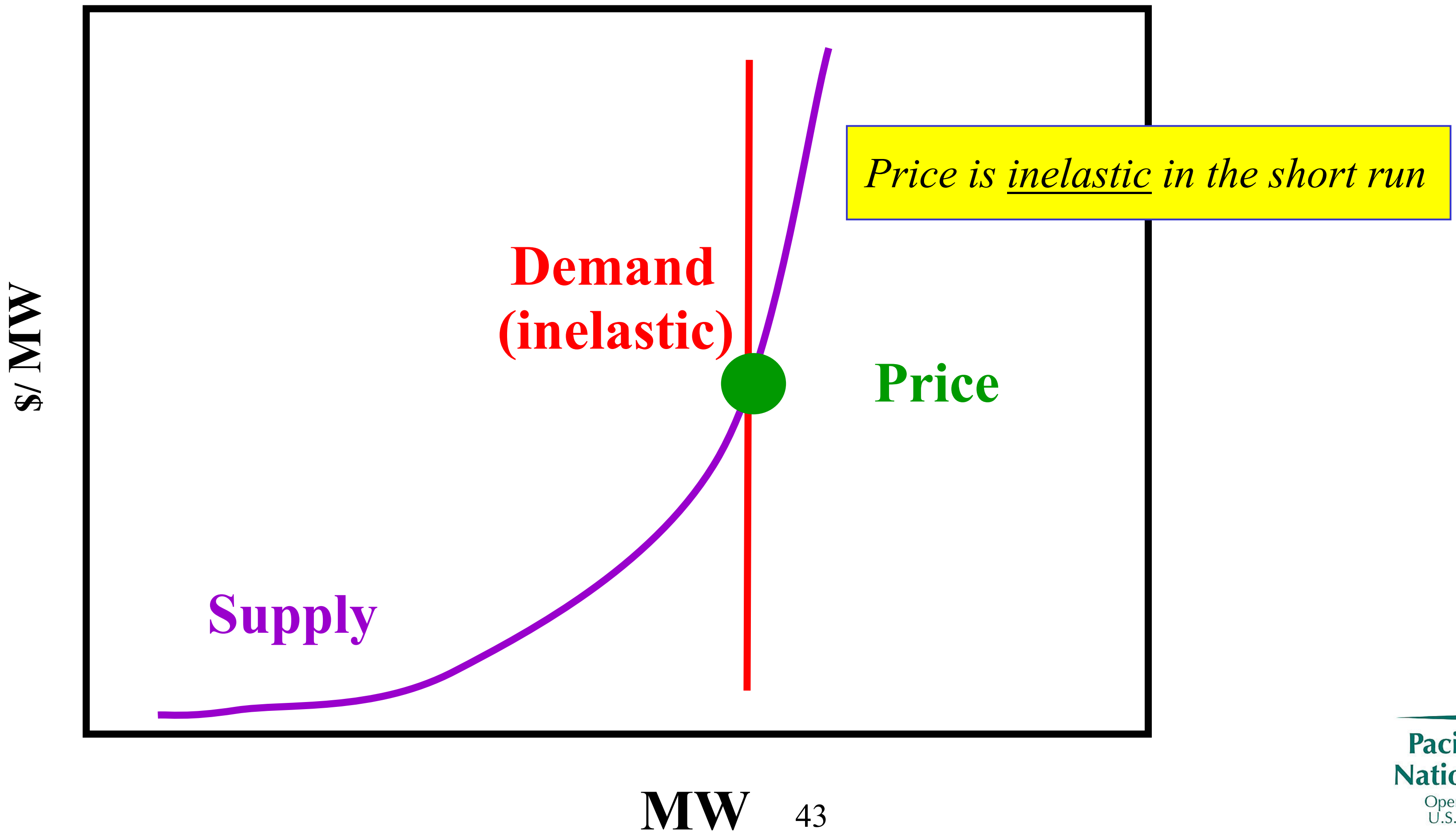
Value of Demand Elasticity



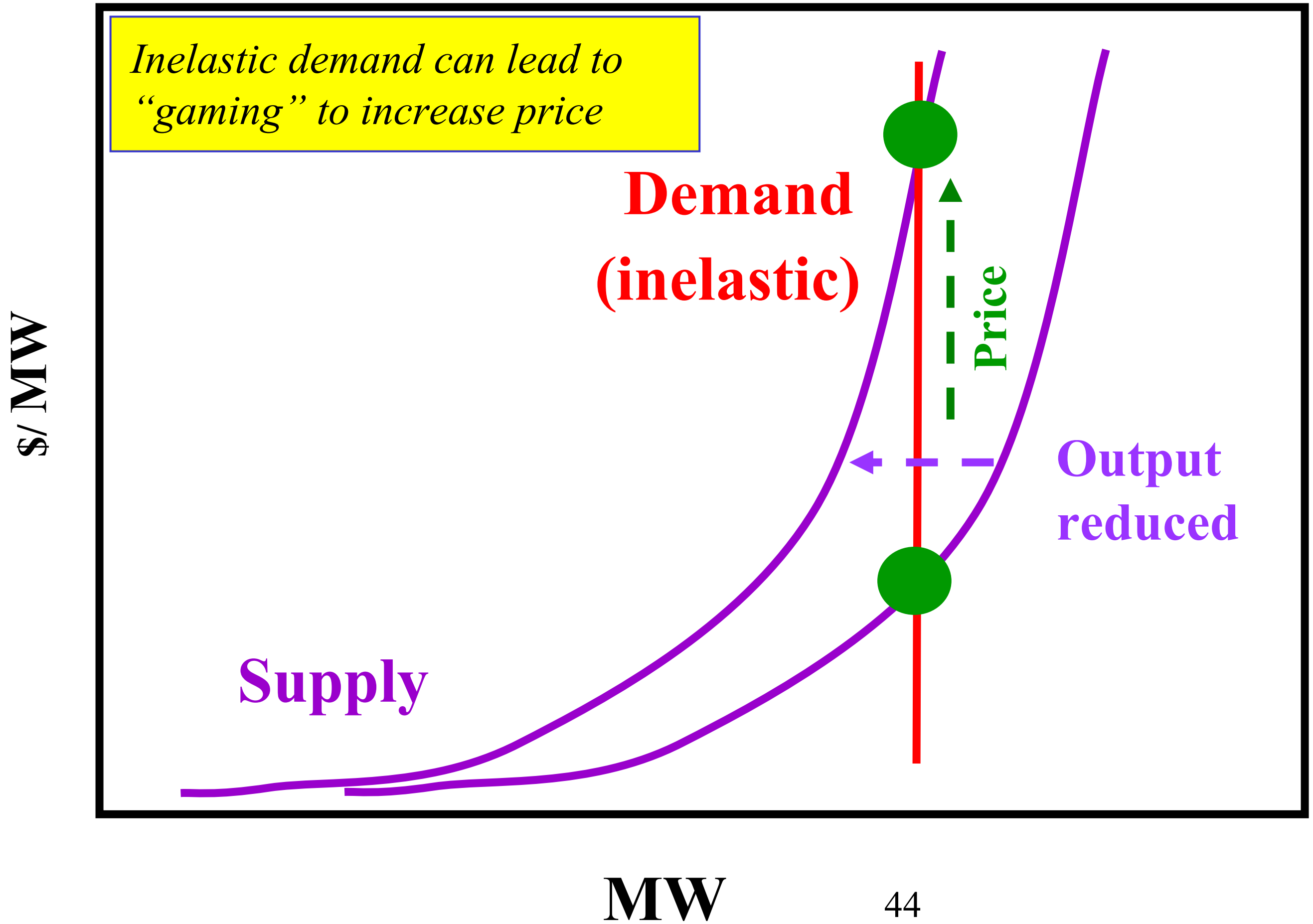
Supply, Demand, and Price Elasticity.

Low price = high demand, low production (unsatisfied customers)
High price = low demand, high *willingness* to produce

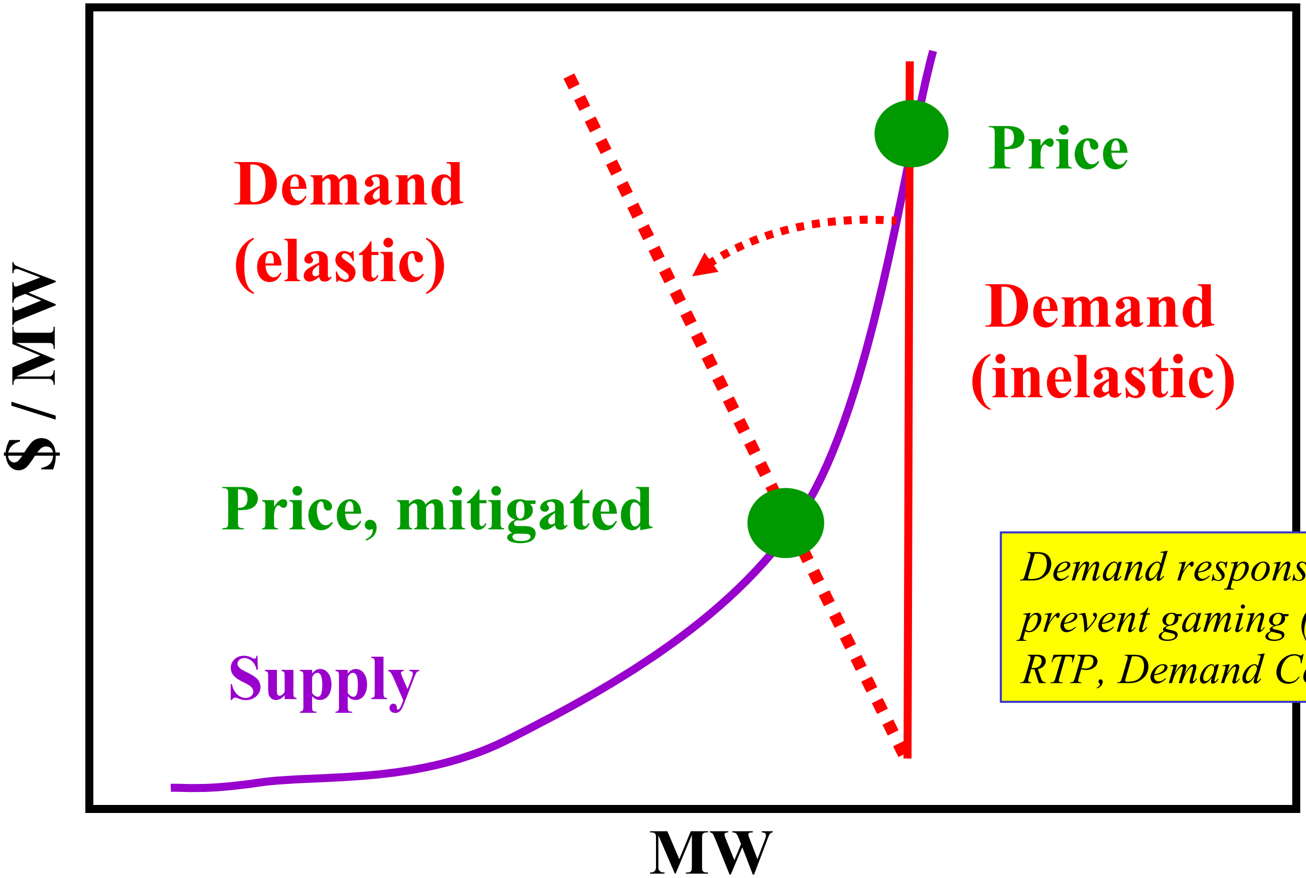
Value of Demand Elasticity



Value of Demand Elasticity



Value of Demand Elasticity

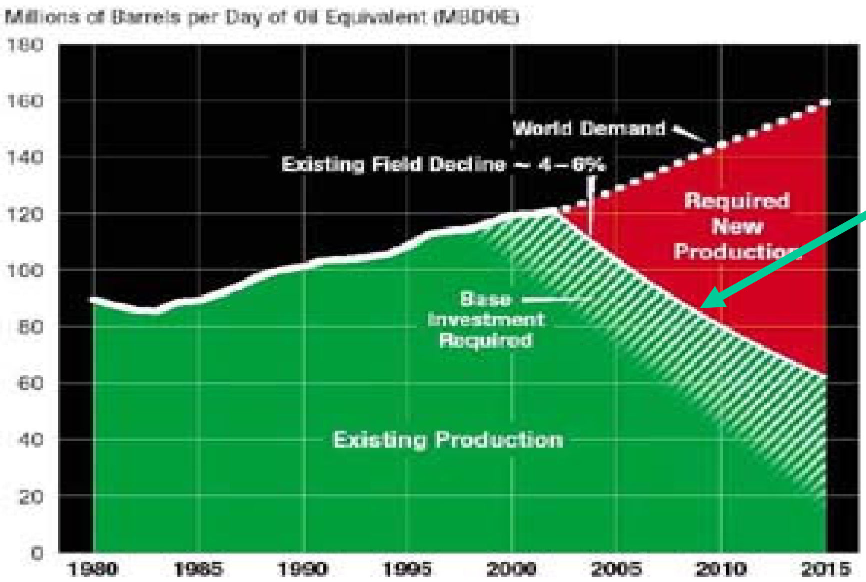


Demand response can prevent gaming (TOU rates, RTP, Demand Control, etc.)

Are We Running Out of Oil and Gas?

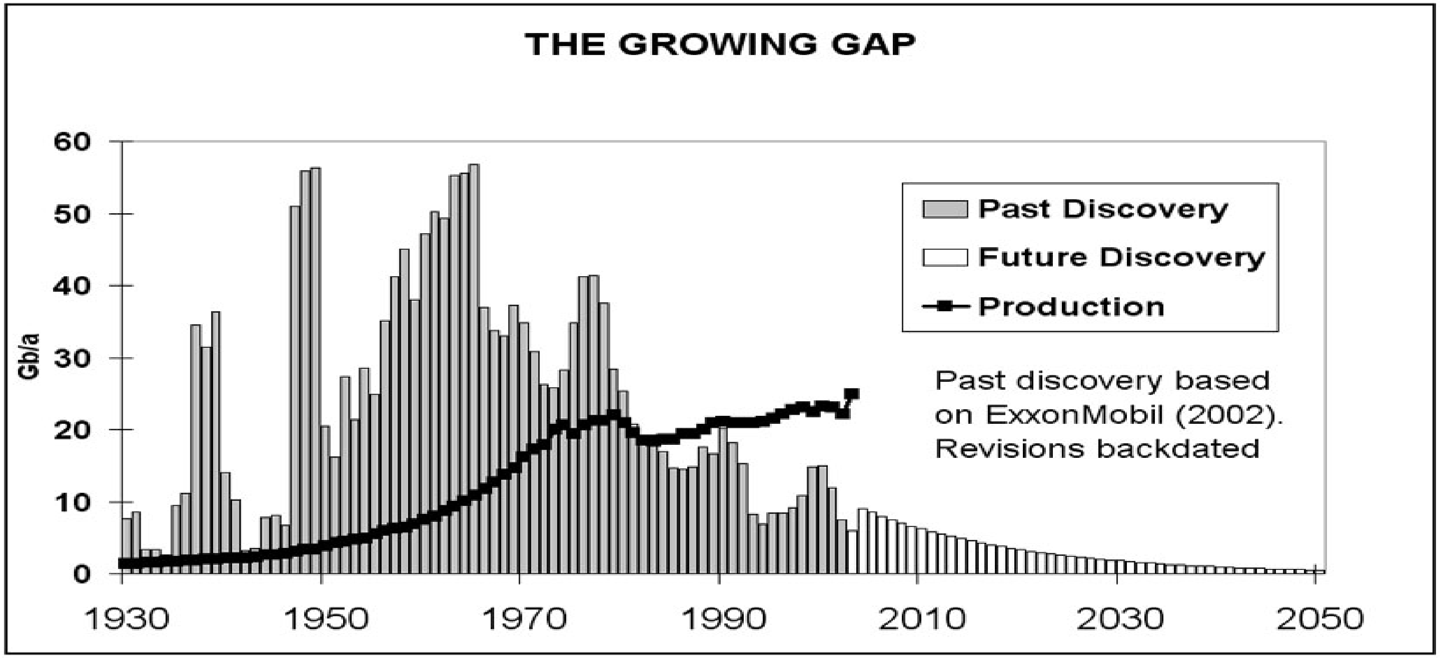
Are we facing a crisis of supply or price?

It Doesn’t Take an Expert to See We Are “Running Out” of Oil

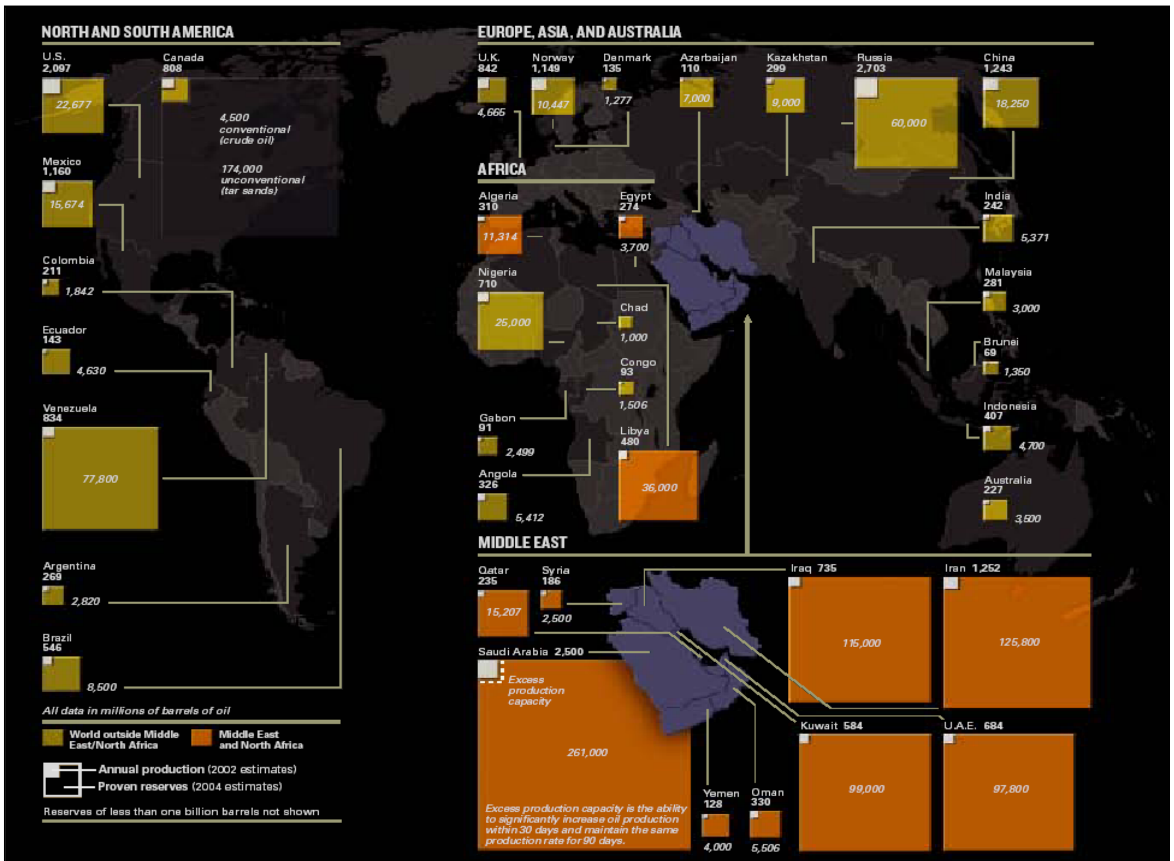


This is known as the “Hubbert Curve”

Where Are the Elephants?



Where It Is…



…if you believe the numbers

Running in Place

- Industry Status Report
  - Firms have to find as much new oil as the pump annually to stay <u>even</u> (that doesn't mean they "run out" of oil or gas, but it does mean they <u>start</u> to run out. That process could take decades.
  - Of the 4 independent "majors," only 2 have done so over the past few years!
  - Most "prospecting" since the mid-1990s is being done on Wall Street, not in the Oil Patch!

Observations

- World demand for oil is projected to exceed the replacement rate between 2006 and 2040 (the Hubbert peak)
- Demand will be rationed by price (prices will continue to increase), although supplies will be plentiful for decades
- Most "oil producing countries" are called that because that is the only basis for their economy. Thus, as oil production peaks, the world will be at risk for price spikes, supply disruptions, and civil disorder in countries that are losing oil revenues.

The Natural Gas "Crisis"

Like most "crises," this is more about price than supply.

We won't see "cheap gas" again.

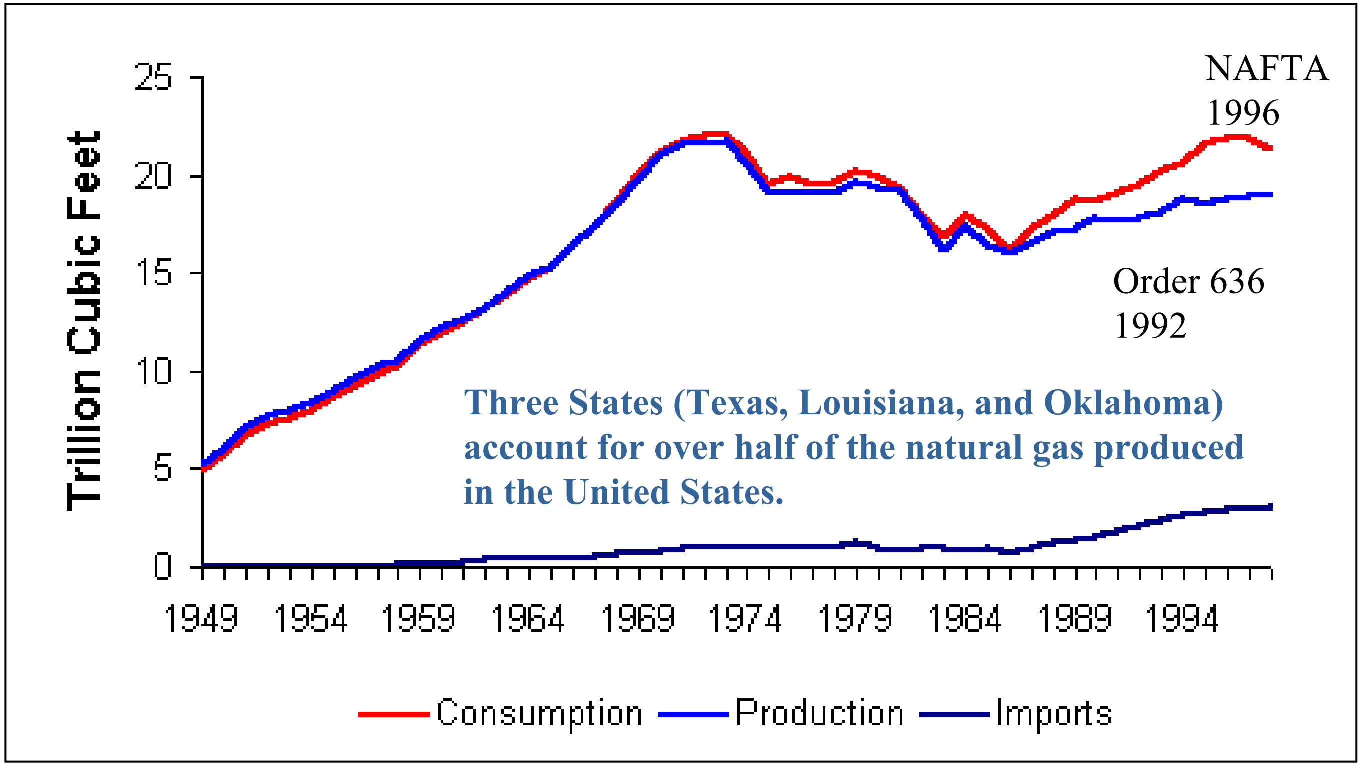
Natural Gas Markets Aren't International Like Oil Markets - Yet

- It isn't "universal" because it isn't a mobility fuel used worldwide
- Natural gas is primarily used for
  - Industry
  - Heating
- It is currently a domestic industry (not international) because shipping is expensive and hot climates and underdeveloped economies don't have much demand for gas.
- US gas prices tend to trade in a range governed by the price of substitutes (long term)
  - When oil prices are low, it substitutes for gas in industrial and some heating applications
  - When coal prices are low, it substitutes for gas for power generation
  - When coal prices are high, gas is used as a substitute
  - Imports (from outside of North America) are not a significant factor in domestic markets – yet!

Key Parts of the Story

- Domestic demand exceeds supply.
- Conventional supplies are playing out.
- New ones are less well understood,
- and, they are playing out faster (just like for oil).
- Industry has to run faster to stay in place,
- but can (and will) rely more on imports of LNG.
- Imports cost more (expected price ~$4-5 vs $2.5).
- The economic recovery will really jack prices up by
  - Increasing industrial demand (despite shifts off shore)
  - Increasing power demand (most of it from gas fired generators)
  - Increasing summer demand for generation
- High gas prices = high power prices!

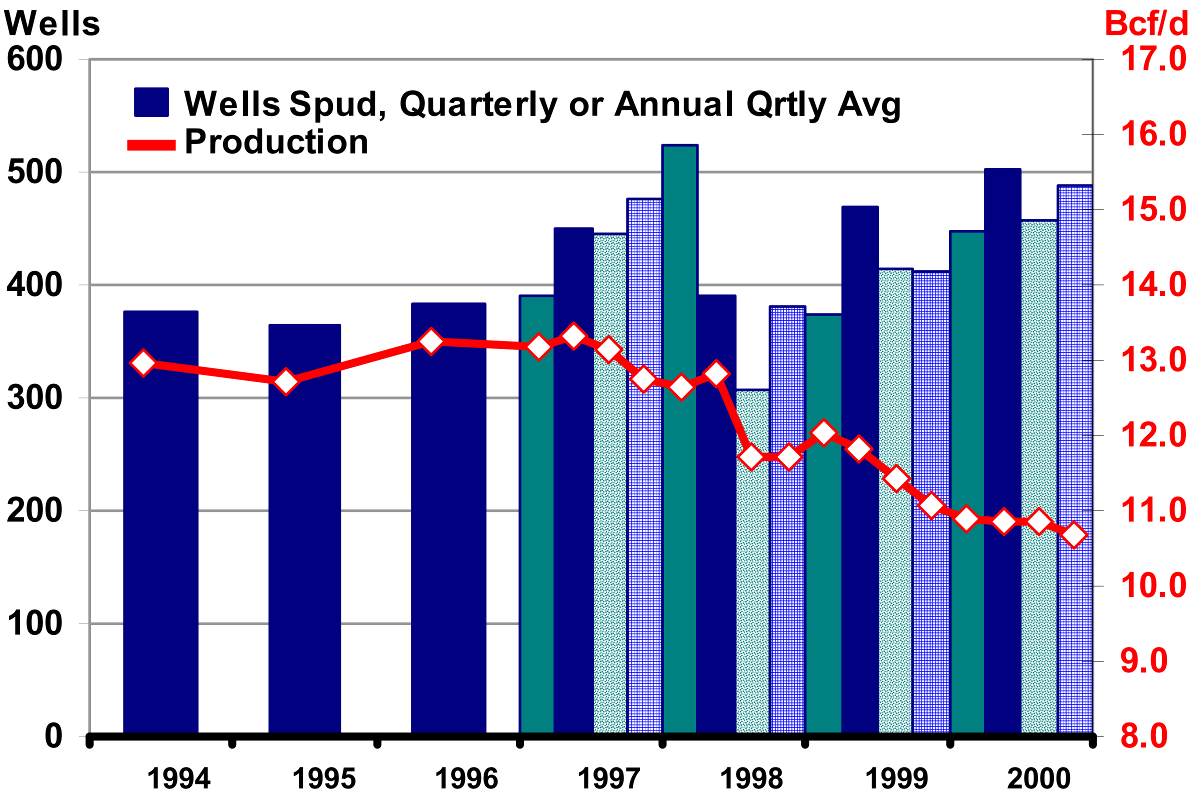
Are We Running out of Gas?



US demand began to outstrip domestic production in the late 1980s, but Canadian imports filled the gap thanks to FERC & NAFTA

Source: DOE EIA Annual Energy Review, 7/7/99, Energy in the United States: A Brief History and Current Trends

Conventional Wells Are Playing Out



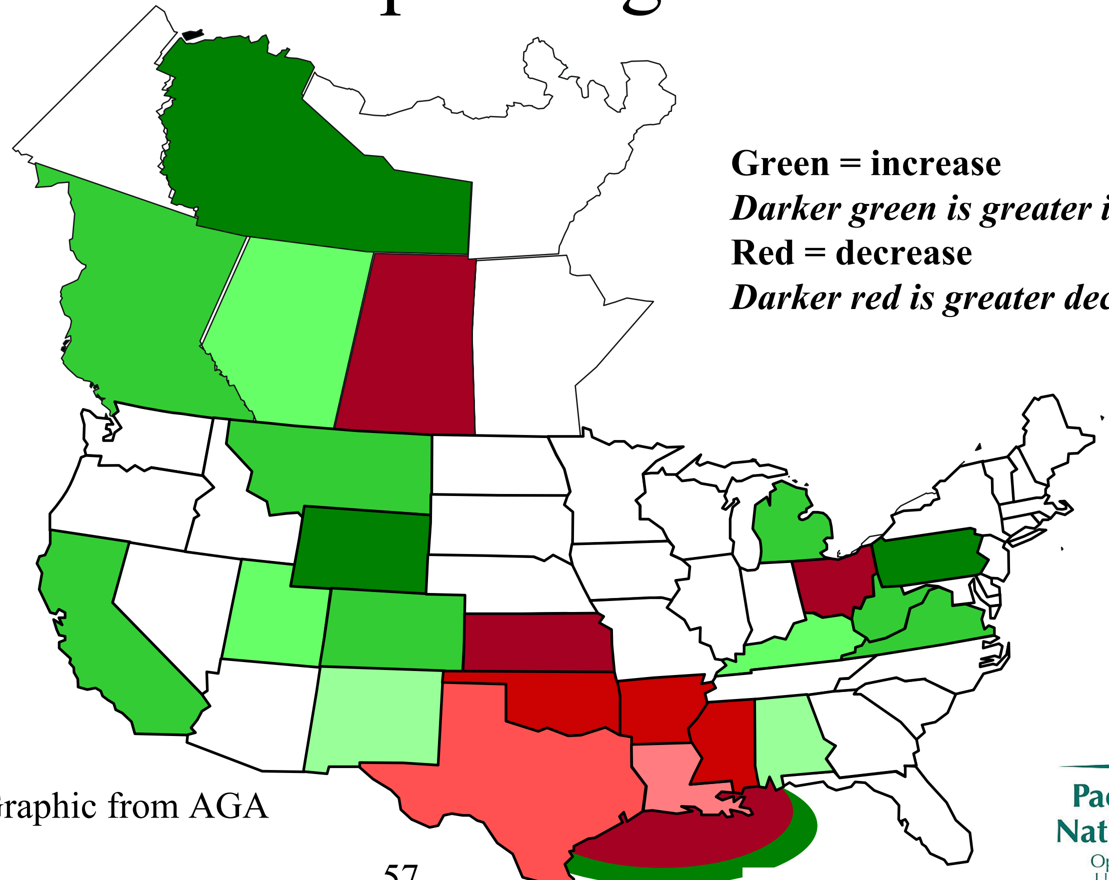
Production & Wells Spud <1000 ft in Gulf

Graphic from AGA, Source: NRG Assc., APC

E&P (Exploration and Production) Activity is Moving to Less Developed Regions

Change in Gas Production:

1995 vs. 2000

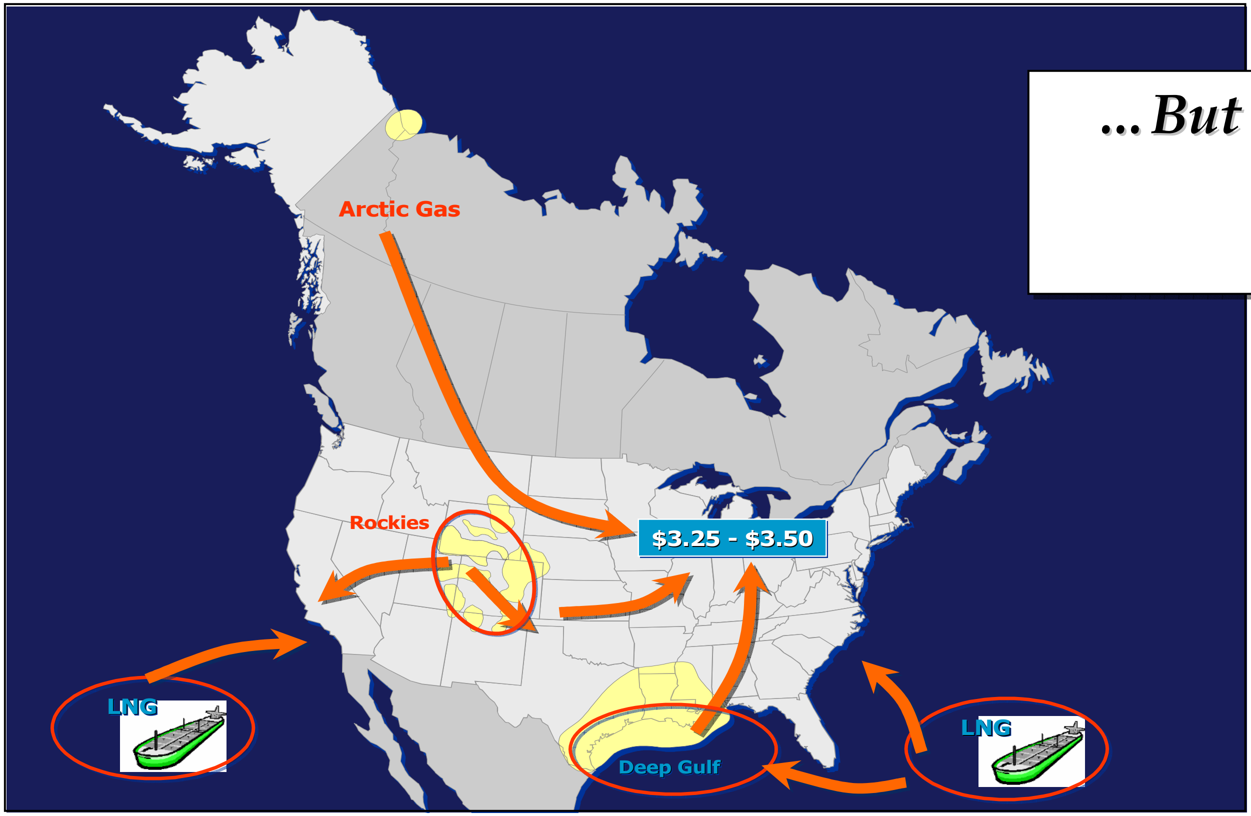


Green = increase
Darker green is greater increase
Red = decrease
Darker red is greater decrease

Graphic from AGA

Source: EIA, APC

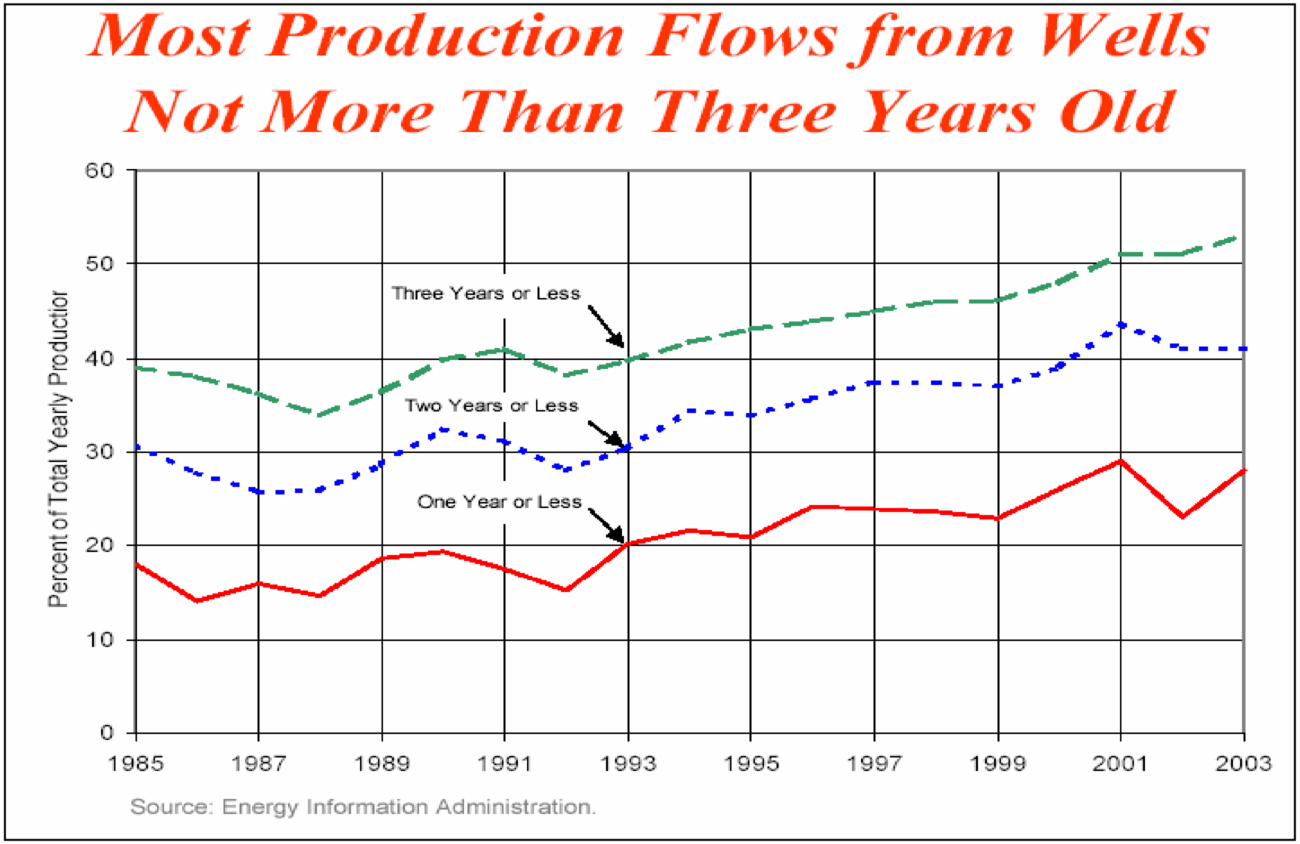
New Supply Must Come from New Areas



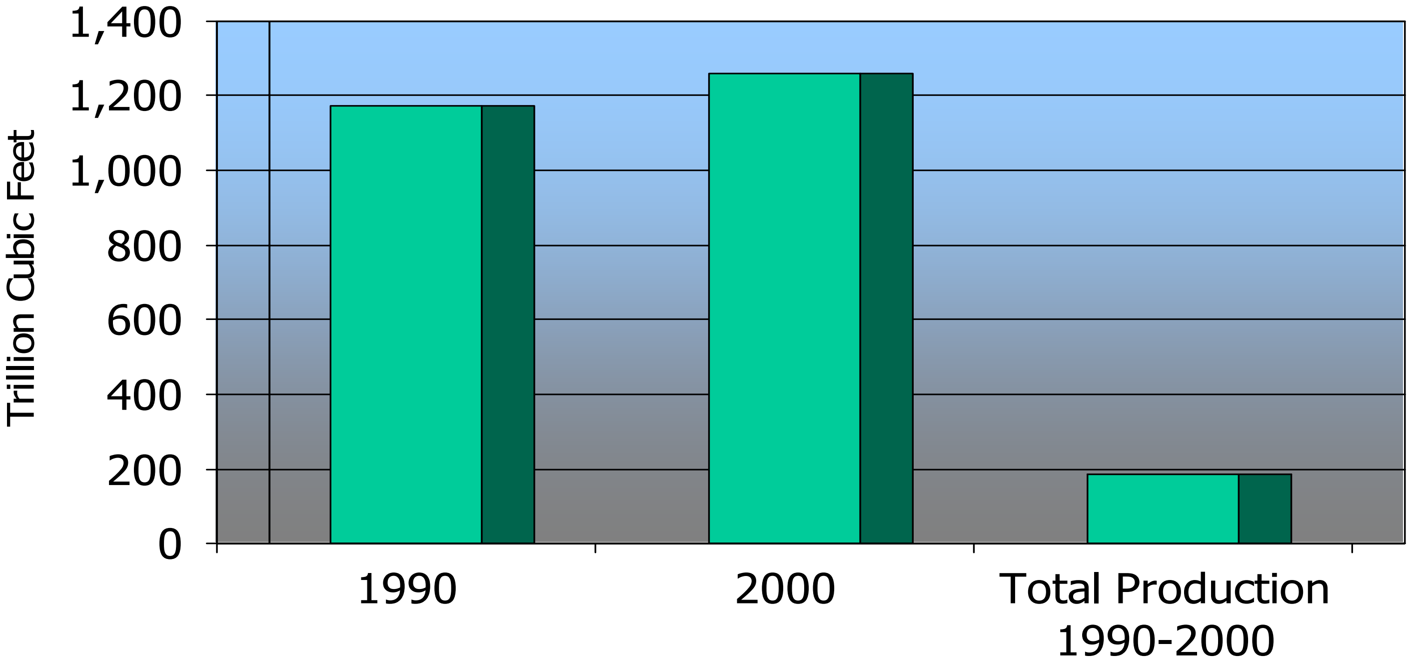
…But Will Only Come at a Price that Supports Development.

Source: CMS Panhandle Companies
Graphic from AGA

New Sources Play out Faster than Expected

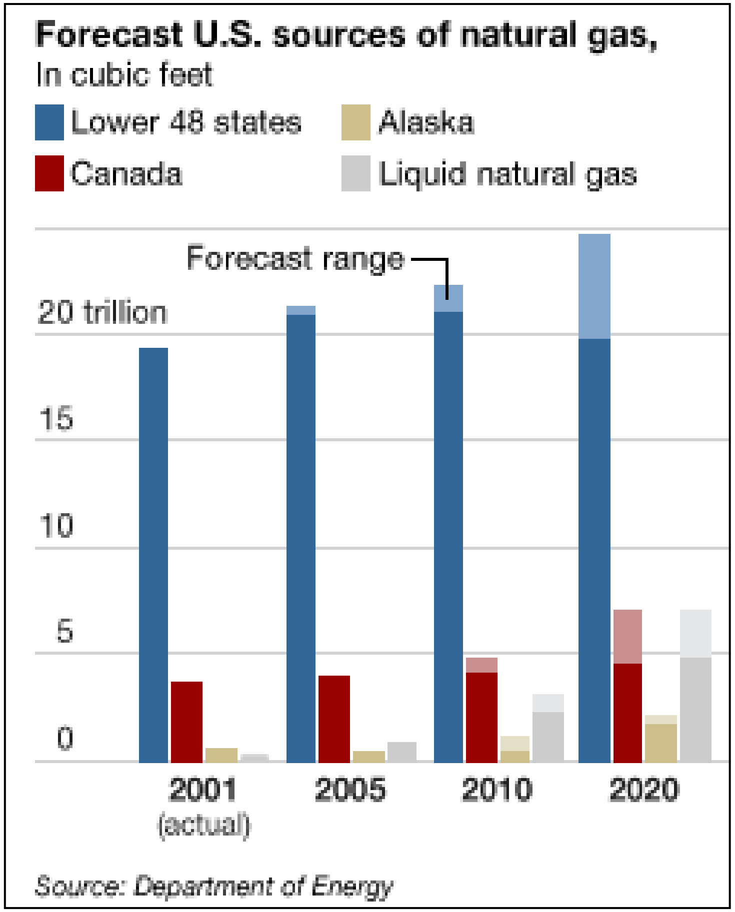


Resource Base Continues to Increase with New Discoveries



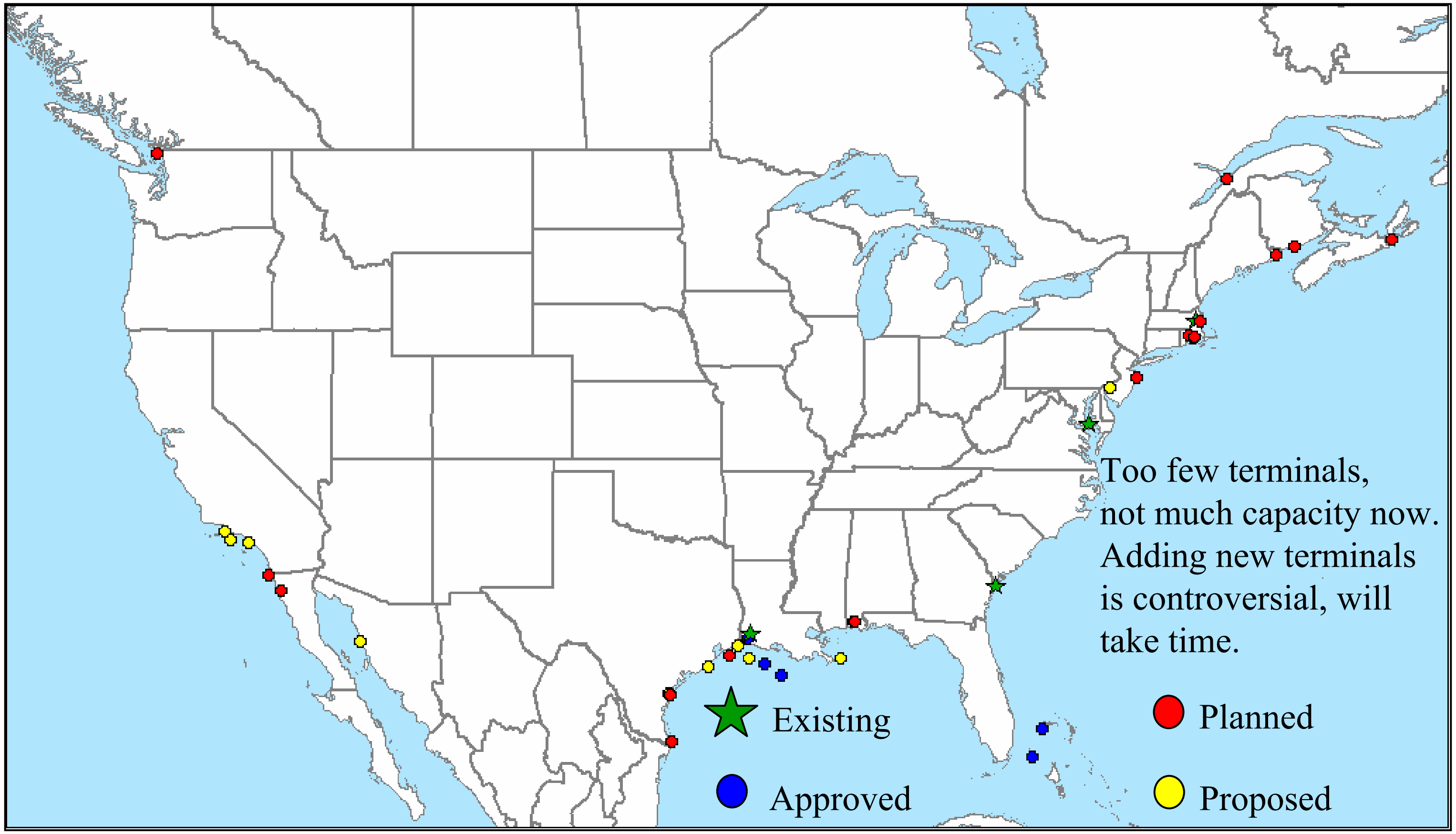
We may be just running in place, but Not Running out of Gas (decades of gas left)

We Will Rely More on LNG Imports

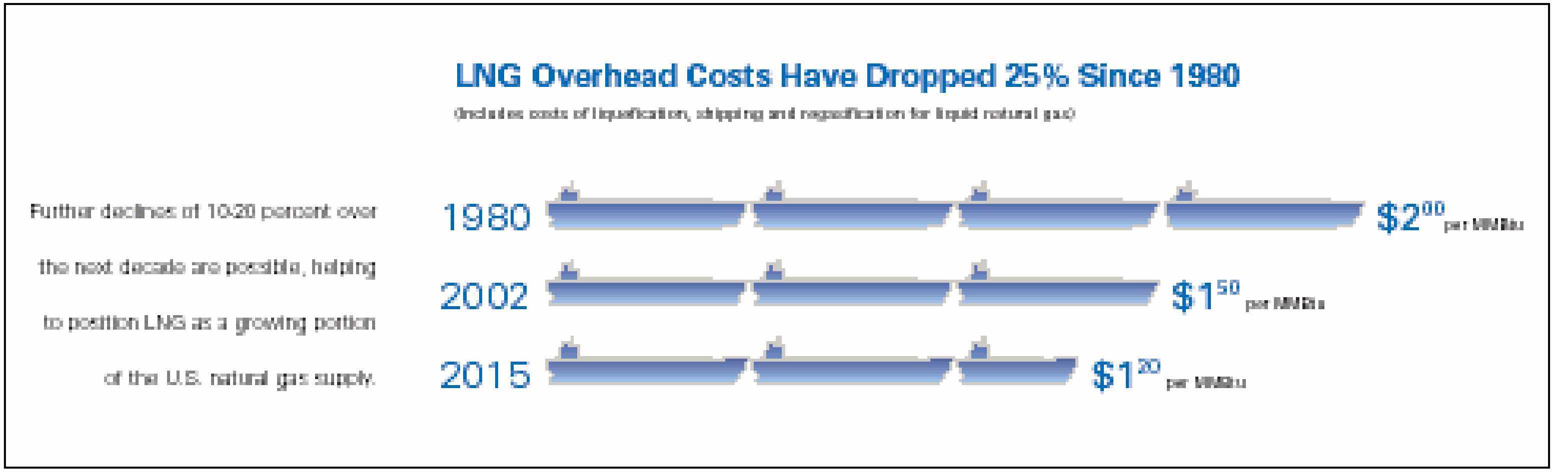


- New sources in the North cost more to develop
- Imports of LNG are expensive – that will increase marginal price of gas (if LNG becomes a significant source)
- LNG <u>may</u> tie gas prices to oil prices

But LNG Won't Be a Big Player Anytime Soon



If LNG Is the Marginal Resource, Prices Will Stay High Due to High (but declining) Shipping Costs.

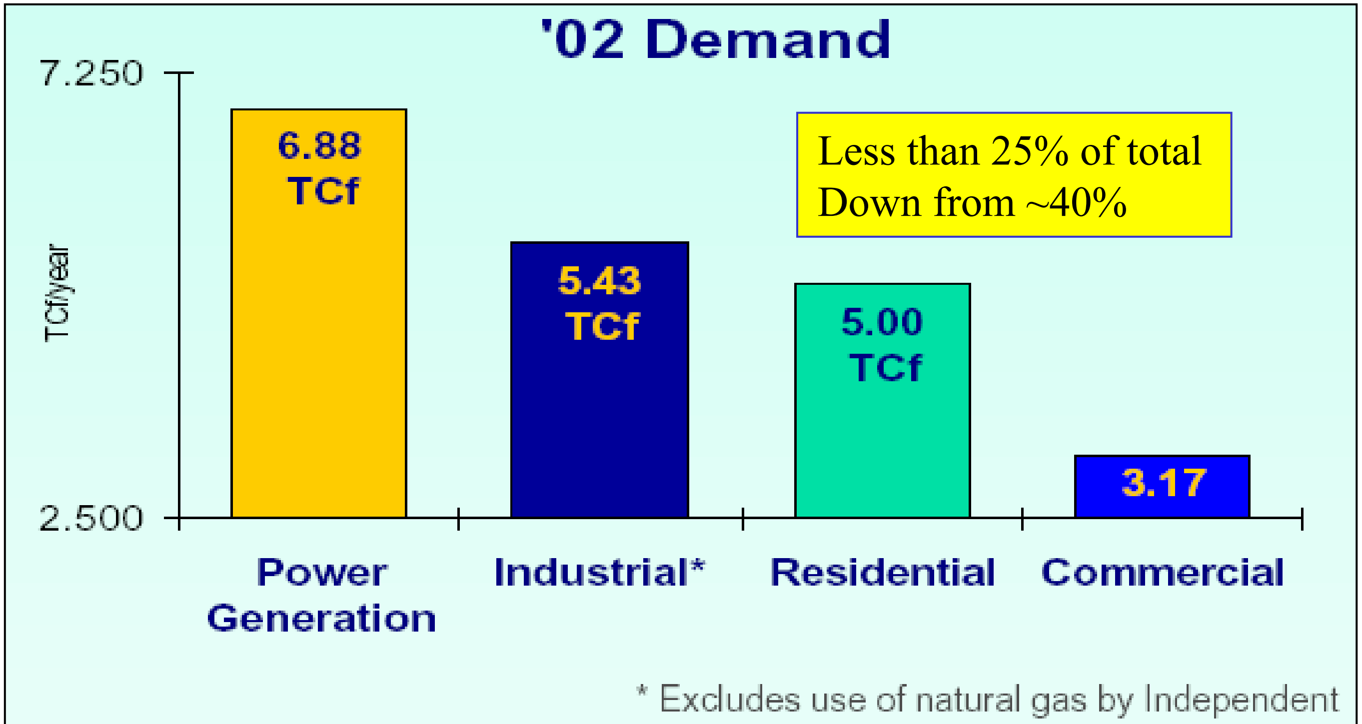


Graphic from AGA

Demand: The Other Side of the Equation

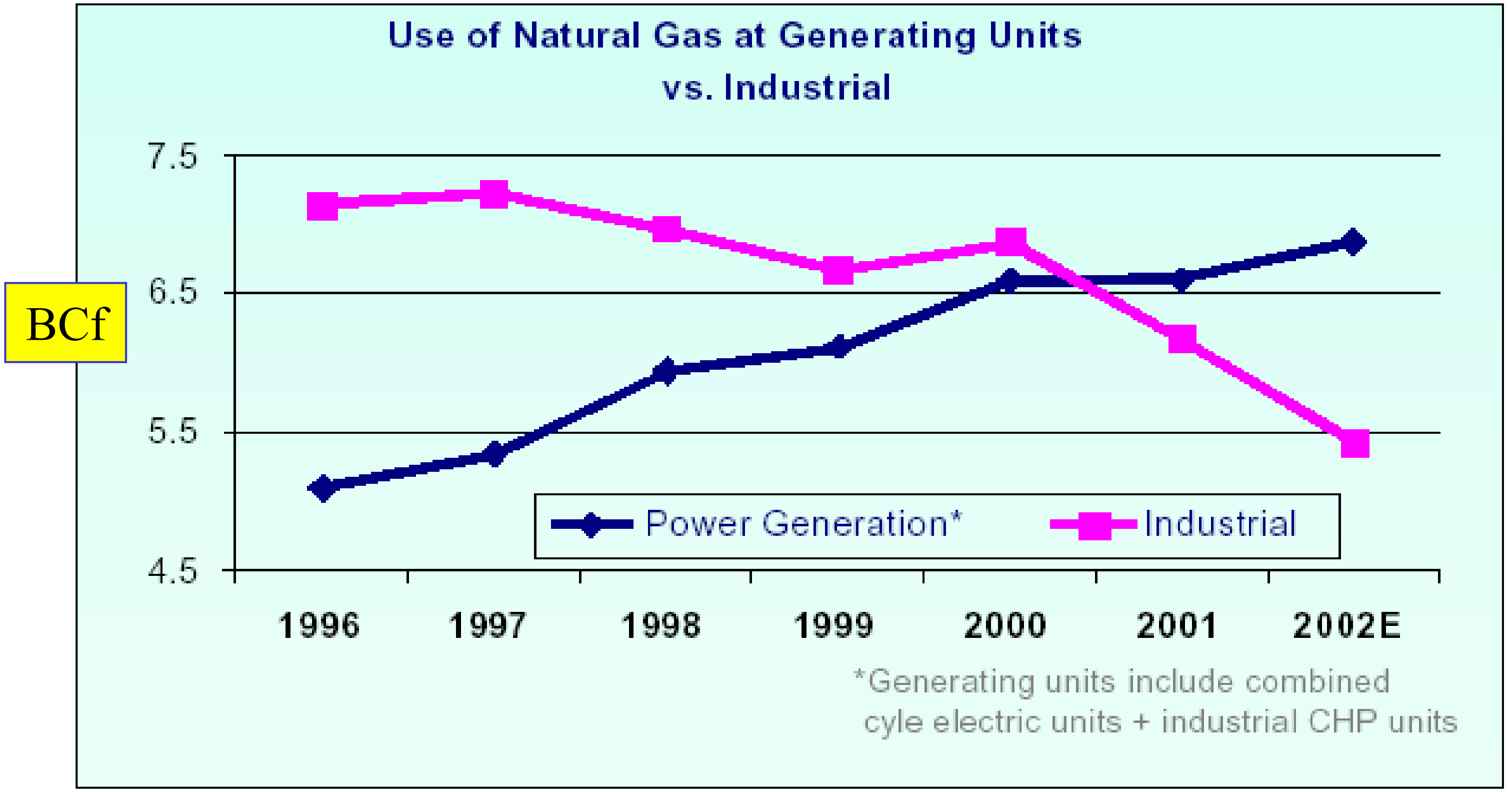
- Industrial demand has been "swing" resource to meet peaks
  - Interruptible
  - Curtailable
- Industrial demand is falling and becoming less flexible (chemicals and fertilizer, not thermal uses)
- Gas power generation is about to have its day.

Industry Shrinking % of Market Less "Swing" Potential



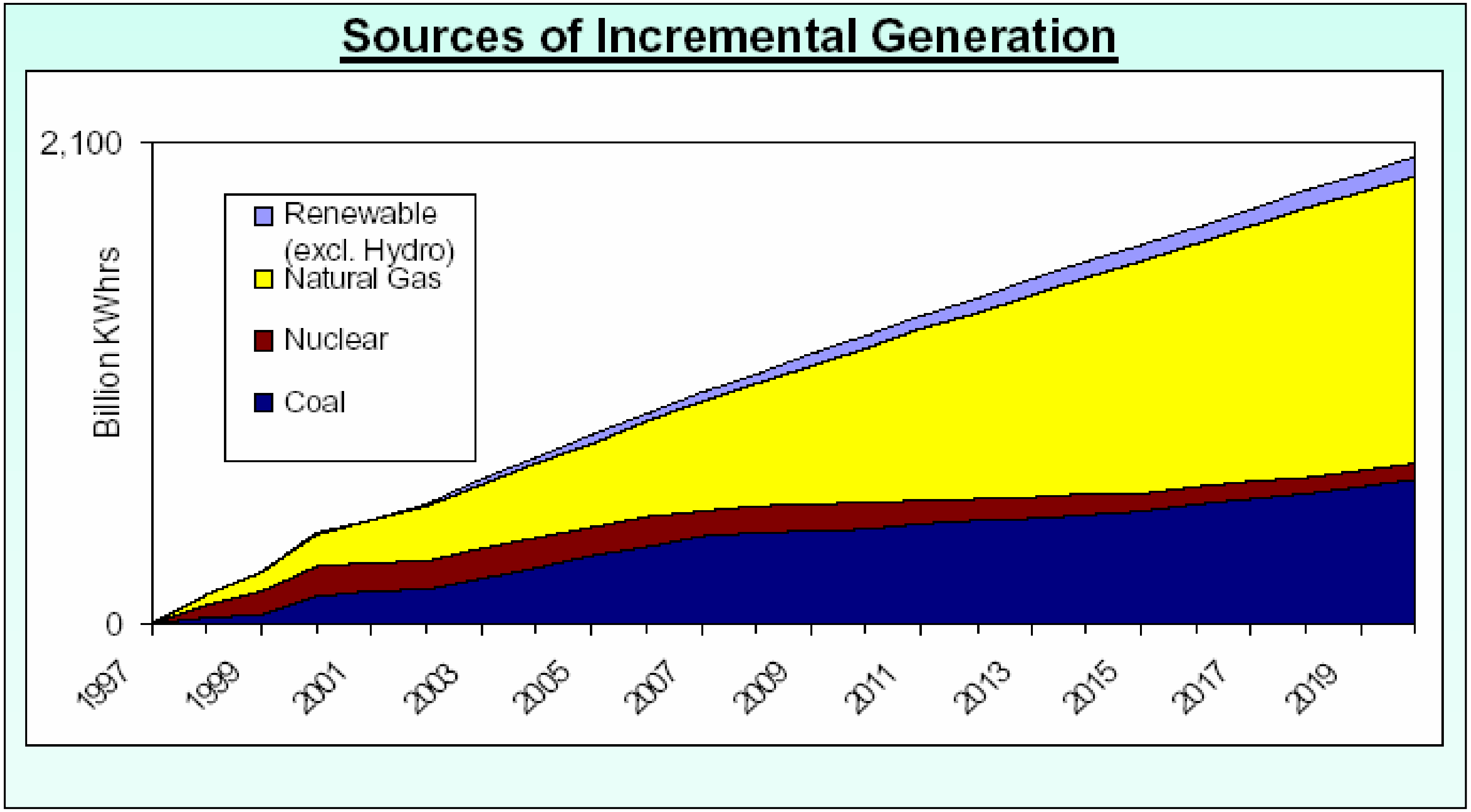
Graphic from A. Weissman

Increase in Generation Demand Offset by Decline in Industrial Demand



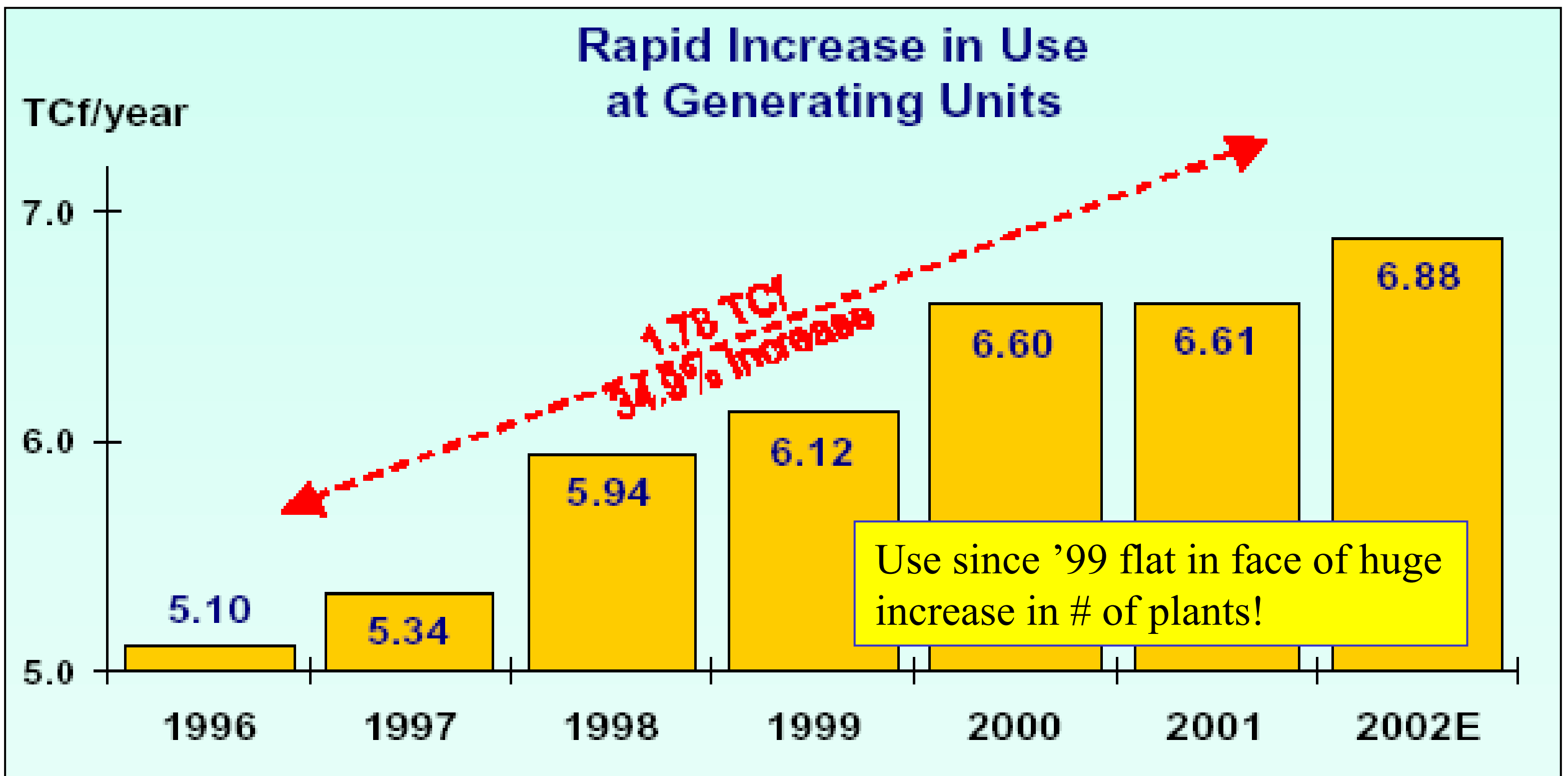
Graphic from A Weissman

Gas Generation May Rule the Market

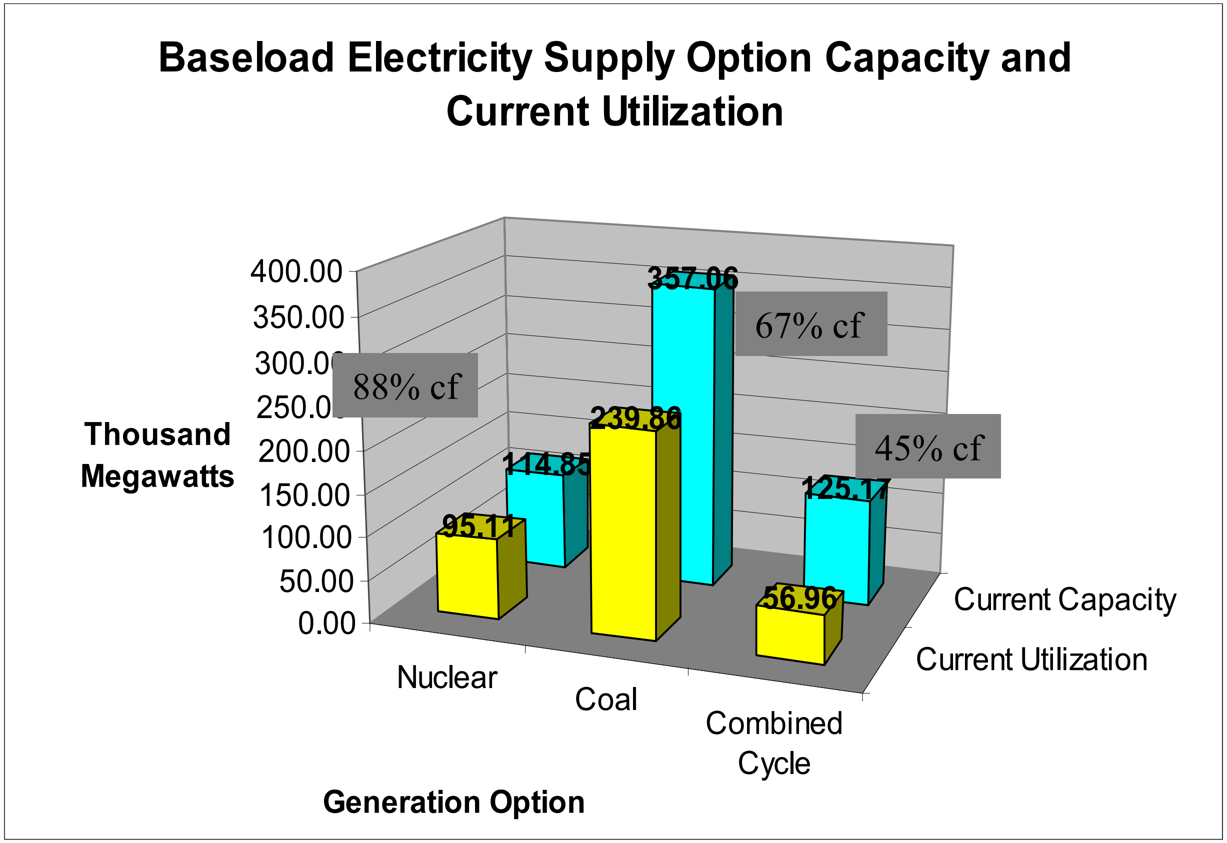


But it Hasn’t Yet

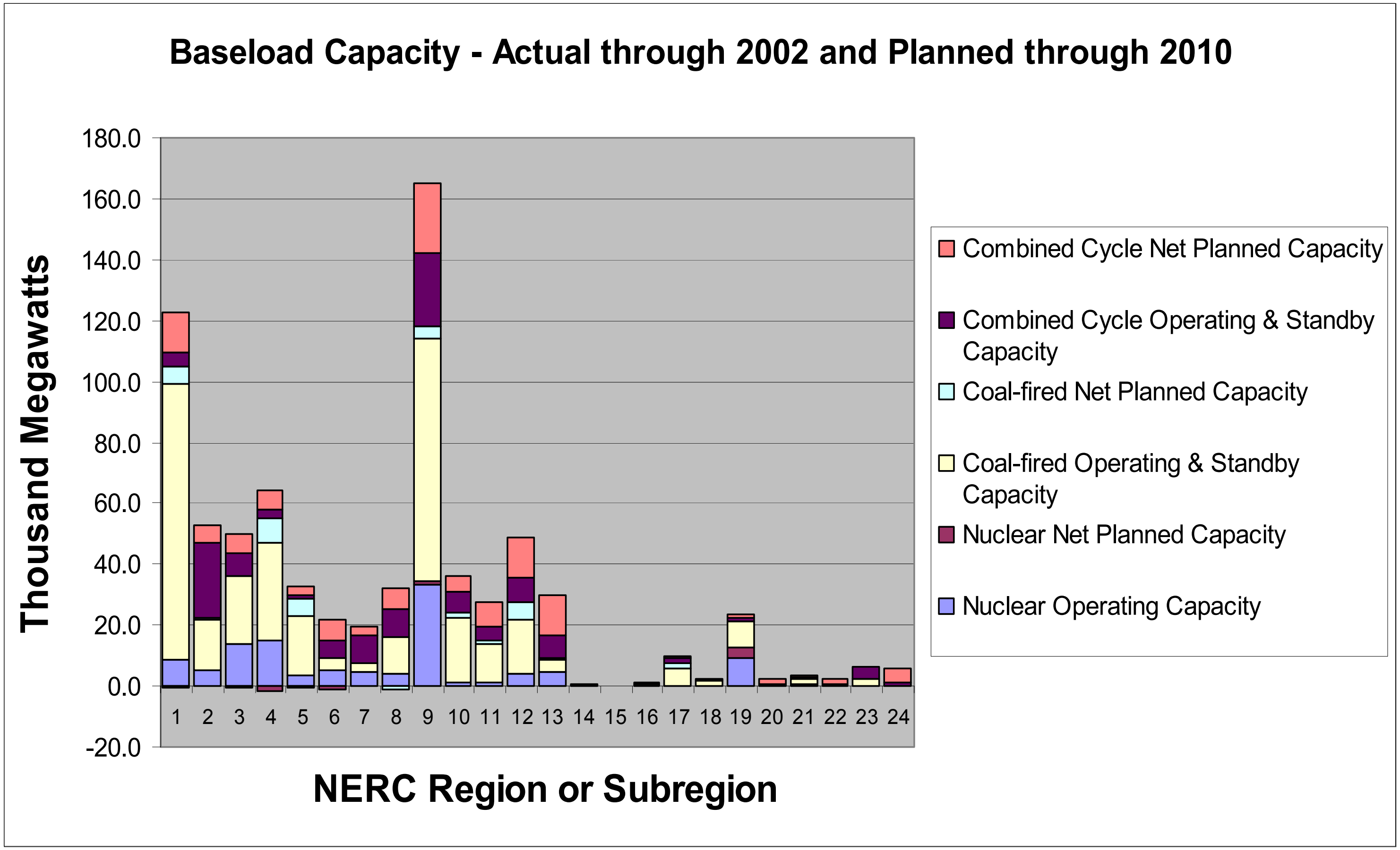
(Rapid absolute increase, small relative increase, <u>up ‘til nov</u>



Because "Old" Coal and Nuke Plants Are Taking up the Slack – Leaving Gas Just for Peaking (new plants can run as baseload).



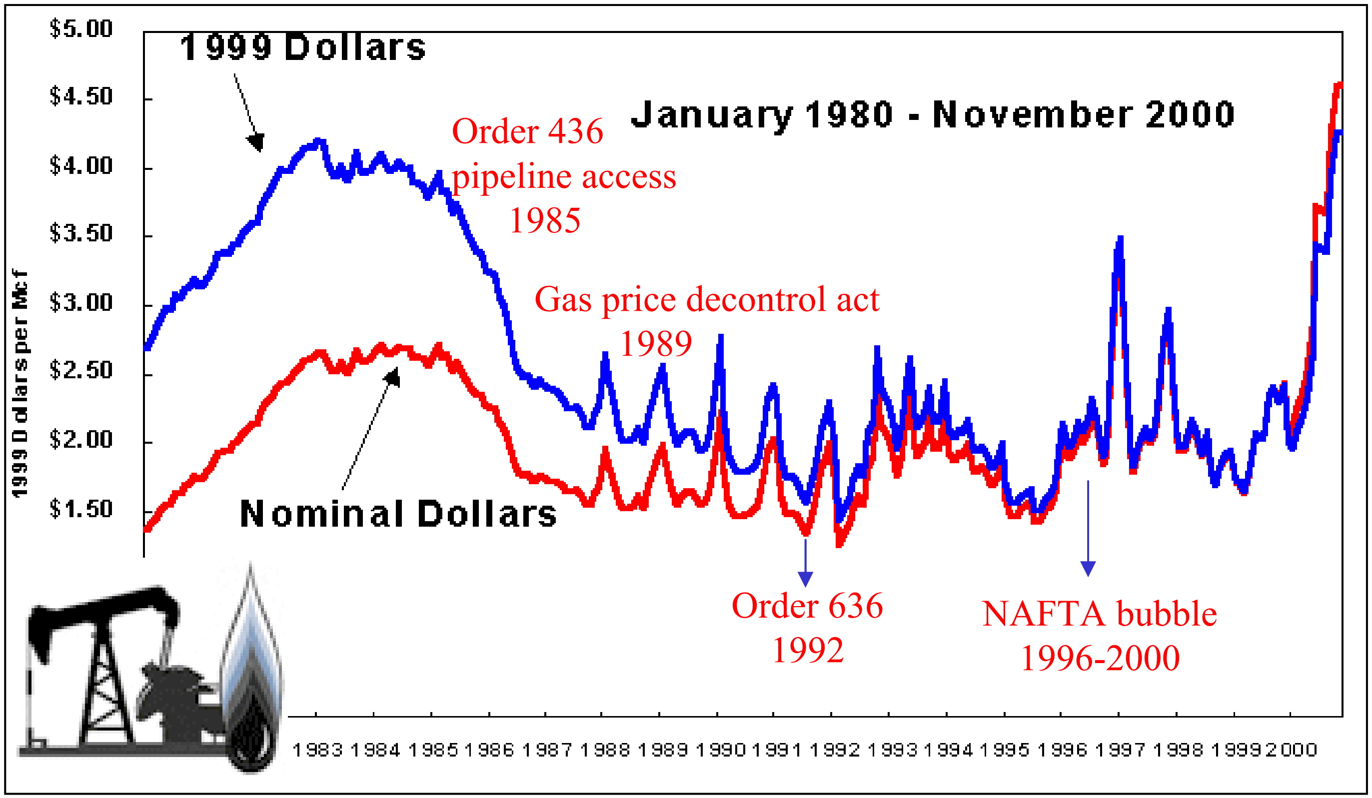
But That Won't Last!



What Will Determine Future Gas Prices?

- How much industrial use remains and grows
- How much of current/new gas generation capacity is used (from ~40% today to 80%?)
- Role of LNG as marginal gas supply price setter
- Clean Air Act enforcement/ New Emissions regulations

Deregulation Brought Lower Prices…

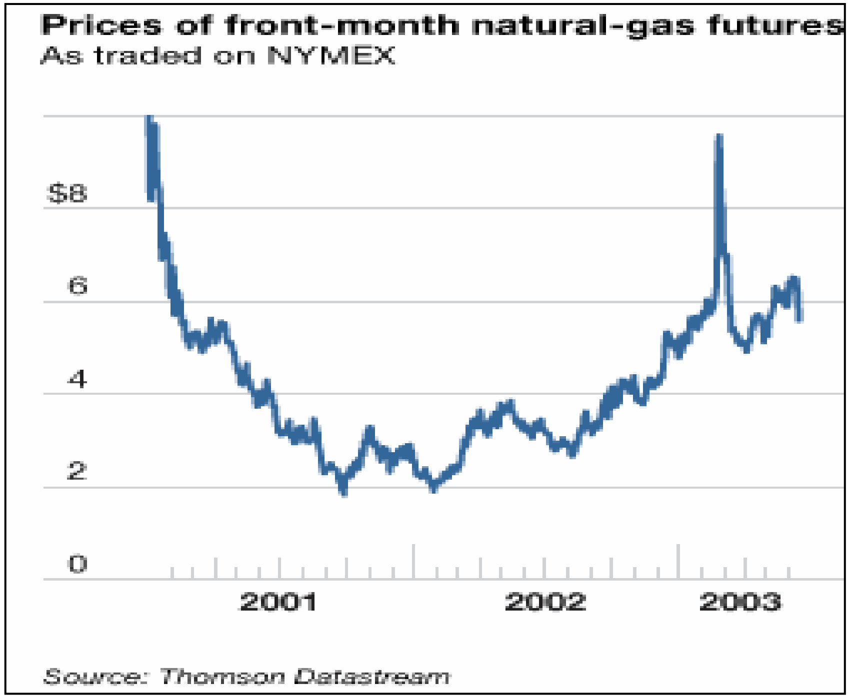


…Was this a one-time change?

Source: DOE EIA

Volatility Has Increased (and this will continue)

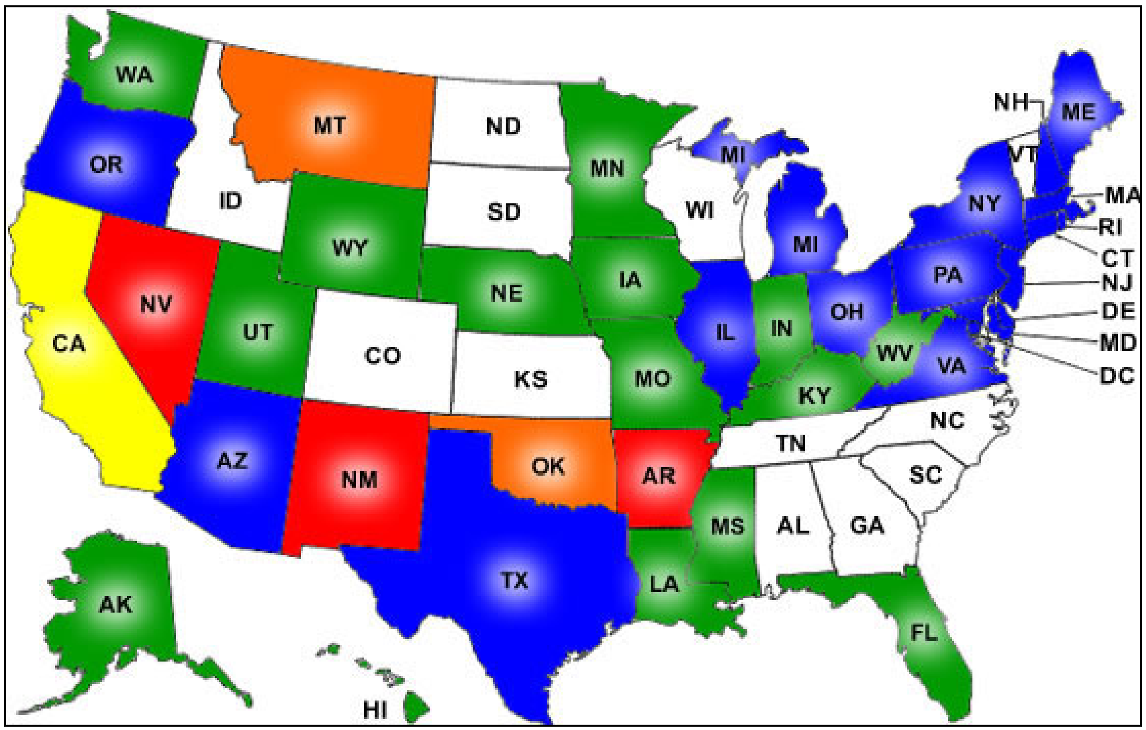
- "Fundamentals" have changed
  - Production fell off due to low prices during NAFTA bubble
  - Manipulation of prices/pipeline capacity shook market confidence
  - Credit crisis forced market to contract
  - Canadian gas imports slowing
  - Increased gas generation keep price pressure on during storage refill season (summer)
    - Storage refill more sketchy
    - Stored gas is expensive



De-regulation/Re-regulation

- Status
- Why it matters
- New “Mandates”

State-by-State Restructuring Status



- Transition Period Begun
- Studying/Monitoring
- No Activity
- Restructuring Suspended
- Restructuring Delayed
- Restructuring Repealed

Observations

- Over half of country deregulated
- Most of deregulated states
- Some backsliding, primarily in response to western energy "crisis" ruining utility credit
- "Opinion Makers" who advocated utility deregulation initially have reversed course. "Integrated utility OK, less regulation needed."
- Many utilities interested in building projects under regulation again (after losing money doing so as unregulated entities)
- No easy way to undo deregulation.

The Oregon Model

- Non-residential/small commercial
  - Non-residential customers have annual "open season" to choose new suppliers
  - Choice window is short, making aggregation difficult (as well as competitive offers)
  - Choice customers can return to "standard offer" service during contract period but they have to pay a return fee.
  - Few customers are leaving

The Oregon Model

- Residential/Small Customers
  - Utilities required to offer default service using regulated assets (existing generation at cost-based rates)
  - Utilities required to offer a “menu” of choices
  - Menu must include “green power,” which is offered by other vendors in most cases (at a premium)
  - This approach is being looked at by other states as an option (such as North Carolina) as it preserves “benefits” of old regulated utility for small customers with little market leverage.
  - Utilities are not happy about this solution as it leaves them with a lot of exposure to “load risk” and few opportunities to reinforce their retail “brand,” grow revenues (because they purchase power rather than build own plants), etc.

California's Core/Non-core Proposals
(3 competing proposals so far)

- Sort of similar to natural gas markets today, where large customers can choose to be core or non-core (local gas company) customers for gas supplies (customers still have to get local service from gas company).
- "Leading" proposal if like Oregon plan, but:
  - Terms are for 5-years
  - Choice customers have to pay a fee to return to utility service (up-front potentially)
  - Utility service customers can become "choice" customers within 5-year window, if they pay an "exit fee"
  - All suppliers have to provide reserves for their retail load
- Market purchases to serve loads/reserves are limited to (something like 5%)

Is there Competition in California's Future?

- Core/non-core concept enjoys support (spread across the various versions)
- No dates set for implementation
- Current State-owned supply contracts phase out starting in 2008
- So, not likely before 2008
- But, Governator and others concerned about shortages in 2006-8 time frame. May make commitments that delay or complicate implementation.

Regulation Under Another Name

RPSs, POLR Service, etc.

- State legislation and Commission regulations continue to place requirements on utilities and competitive energy service providers (ESPs) that “undermine” choice.
- Renewable Portfolio Standards (RPSs) require energy suppliers to have some fraction of resources from renewables
- Need for provider of last resort (POLR) to provide service to all customers regardless of credit, etc. resulting in that need
- Public benefits funding from distribution fees collected to fund efficiency, on-site renewables, etc.

POLR

- Typically, POLR service is reserved for customers who did not choose an alternate supplier or could not get service (due to bad credit, etc.)
- Typically, POLR service is expensive because load is unknown, payment risk is high, etc.
- Typically, energy supply is competitively awarded, but …
- If competitive bids are too high, states often cap the price leaving the utility with the job.

Public Benefits Funds

- Surcharge on distribution customer bills (a few %)
- Funds often go into 3rd party fund, not utility account
- Typically fund projects for small customers (often not feds despite our payments)
- California uses them to pay down extra costs from RPS purchases

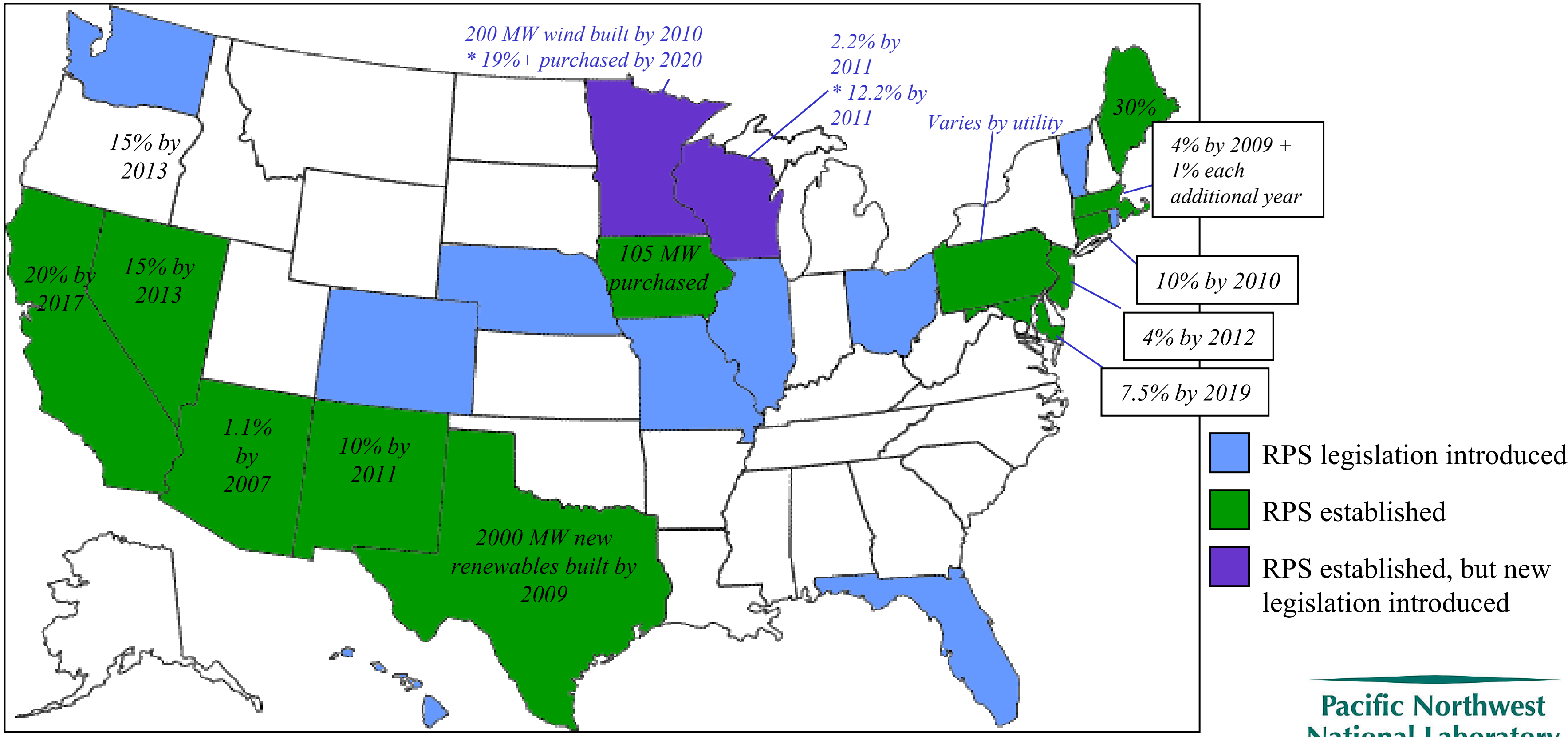
Renewable Portfolio Standards

- Status report
- Overview of approaches

RPS: Overview

- In non-choice states, utility required to procure x% from renewables. Penalties may be imposed if they miss the goal (but that raises rates and gets sticky).
- In choice states, it gets complicated
  - CA requires "choice" customer suppliers to comply, but "count" green power of customers in their requirement
  - PJM states are mostly deregulated. RPS falls on "suppliers." Green power "credit" towards RPS goes with the supplier unless the customer chooses to keep it. If they keep it, it doesn't "count."
  - Suppliers who fall short, have to pay a fee (~2 cents/kWh) which they can collect from their customers (including those who bought green power and kept the credits – like us!)
- Lots of support for RPSs, even among Republicans and some utilities (as it gets them back in the power development game)
- "Trading" schemes are favored but are not mature yet. As they develop, trading "tags" will facilitate the process (trading "tags" are NOT the same as "green tags")
- Not clear how solar thermal projects count (solar water heaters and daylighting substitute for purchased energy)

RPS Status across the U.S.



Green Power Options

(Absent an RPS or Other LT Buyer, there is NO Market for Green Power)

- Green power purchases
- Green tags
- On-site power
- Off setting purchases

Green Power Purchases

- A purchase of power (real electrons)
- Price tied to cost of project or portfolio of resources or prevailing green power market
- Price can be in terms of energy (kWh when project produces power – when the wind blows)
- Firm, shaped power requires access to non-green resources (probably), although all energy (kWh) may be all green

Green Tags

- "Green" attribute of project is sold independent of energy attributes (except for energy – kWh – content)
- Energy attribute is sold as "just energy" at prevailing market price
- Tags can be traded in renewable energy credit (REC) markets in many states
- Validity of tag is assured through one of several auditing organizations
- PJM is planning its own market and auditing process. Some states in PJM area require suppliers to "surrender" green tags for in-state customer purchases instead.

Green Power versus Tags

- Power can be purchased "at cost" if purchase tied to facilitation of specific projects (the contract allows the developer to finance project construction). Price may be higher or lower than prevailing power price over duration of contract.
- Power price is "fixed" independent of prevailing "other power" market (no fuel price risk).
- Green tag is purchase from an existing resource or portfolio in addition to (on top of) "other power" purchases.
- Always "costs more."
- Tags are easy, but harder to explain to procurement, contract, and other staff.

Green Power Challenges

- Because delivery of green power requires firming, shaping, and transmission, it is complicated. Wind/solar only produce power 35/20% of the time.
  - Output from specific projects doesn't match daily loads, so "make up" power from other (conventional?) source is required.
  - Projects may be located far from load and transmission path may not exist (at least over LT)
- 100% green power may require 5 or more times (for solar) as much installed capacity as load.

Green Power Variations

- Green power purchase can be just a financial transaction where PPA enables development but output is sold locally rather than delivered to customer and replacement power (could be conventional) is used to meet load. Accurate accounting is important.
- Only works if there is an RPS or other long term market for green power.

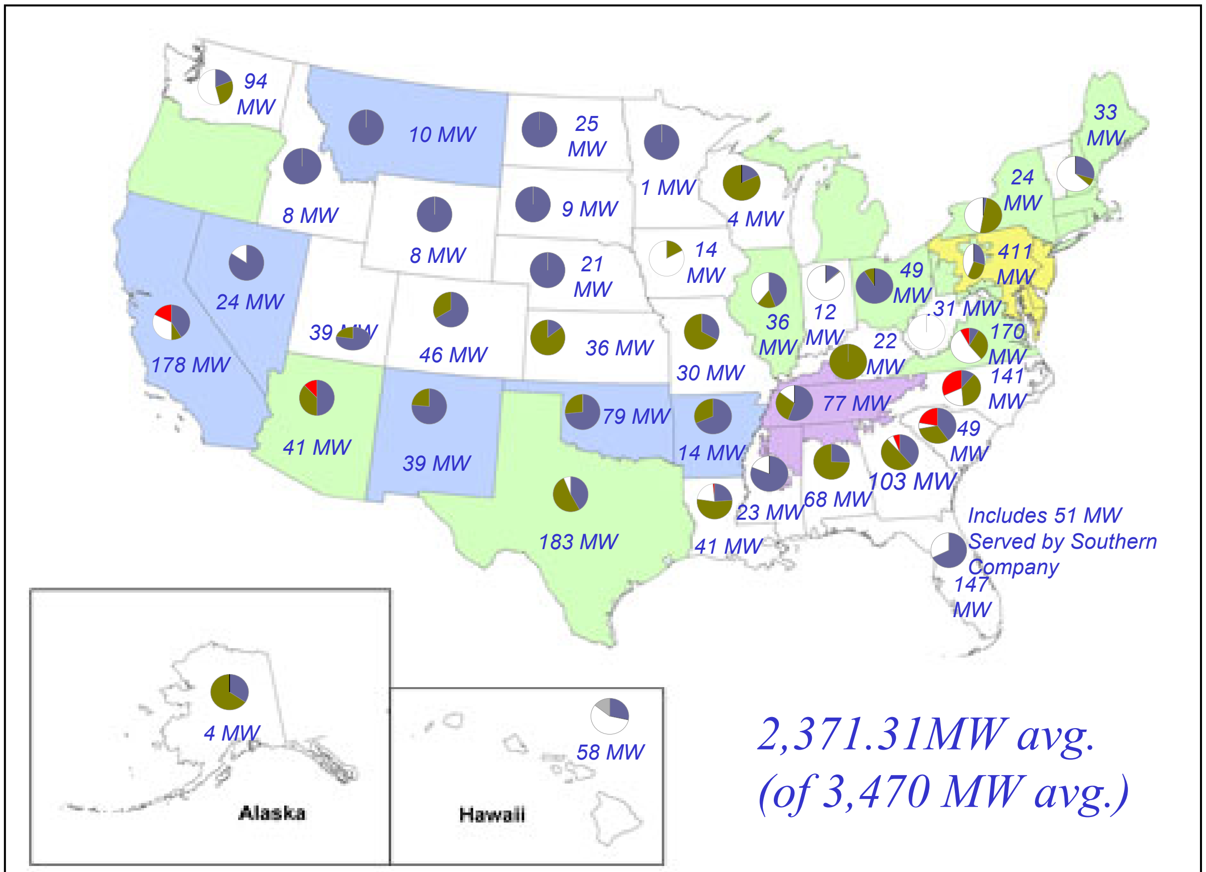
Green Tag Variations

- Tags usually purchased from existing projects (no incentive to “discount”) for 1 year.
- Green Tags can be used to “fix” power price over long term (like green power PPA) if developer can use tag purchase to develop project and/or is willing to guarantee “hedge price” on long term basis.
- Again, only works if there is an RPS or other long term market for green power.

Why Does It Matter?

- Green power purchases appear to be the most direct way to stimulate development of new renewable resources (government purchase contracts can be used by developers to obtain development financing).
- State regulations limit agencies' ability to purchase green power at reasonable rates.
- Federal renewables goals need to be mindful of these restrictions (see next 2 slides for an example).

Example: DOD Loads by State



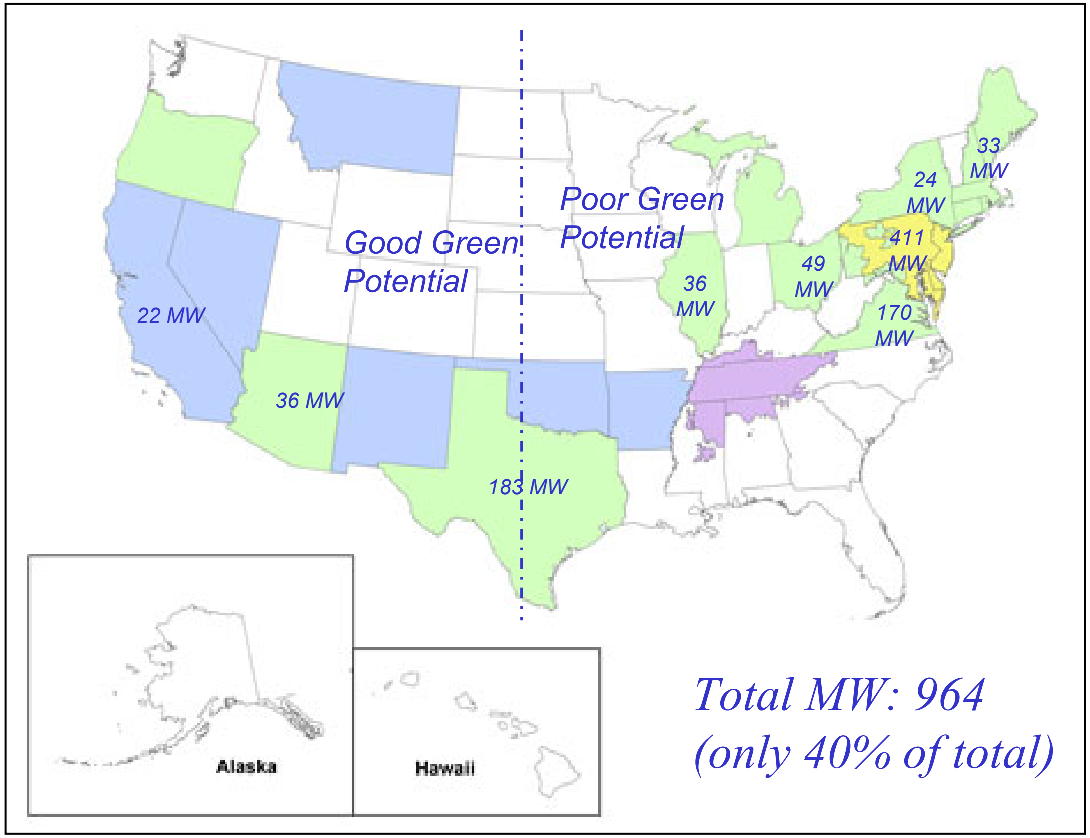
(largest ~400 sites, 2/3rds of total load)

	U.S. Air Force
	U.S. Army
	U.S. Navy
	U.S. Marine Corps

	Deregulation Active
	Deregulation Suspended, Delayed, or Repealed
	Deregulation Not Active

Pacific Northwest National Laboratory
Operated by Battelle for the U.S. Department of Energy

DOD Sites that "Can" Buy Green Power



(If DOD wanted to purchase 20% green, these sites would have to buy ~60% "green," much in "green poor" states)

(light green)	Deregulation Active
(blue)	Deregulation Suspended, Delayed, or Repealed
(white)	Deregulation Not Active

Pacific Northwest National Laboratory
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State-by-State Review

- Choice
- RPS
- POLR

Delaware

Choice Start Date	Rate Freeze/Default Service	POLR Service
October 1999	Rates Capped from October 1999 to May 2006 for Conectiv Rates Capped from April 2000 through March 2005 for DEC	Conectiv until May 2006 – medium/large customers RETURNING to SOS are charged a variable market-based price. DEC default supplier for its customers.
Customer Participation	**RPS**	**Green Power Option**
10 non-residential customers (out of 30,425) being served by alternative supplier. April 2004	Legislation introduced: 1% beginning 2006 increasing to 10% by 2018	Yes

Maryland

Choice Start Date	Rate Freeze/Default Service	POLR Service
July 2002	Rates capped from July 2000 – 2003 or 2004 depending on the utility	Yes Local utility is POLR for their territory – fixed-price market based rates
Customer Participation	**RPS**	**Green Power Option**
Non-residential: 5.4% April 2004	Legislation signed May 26: 1% Tier 1 and 2.5% Tier 2 in 2006 increasing to 7.5% of Tier 1 (no Tier 2) by 2019	Yes

New Jersey

Choice Start Date	Rate Freeze/Default Service	POLR Service
November 1999	Rates capped from August 1999 through August 2003	Yes - Basic Generation Service – largest customers charged hourly market-based rates, all others have fixed-price option.
Customer Participation	**RPS**	**Green Power Option**
Non-residential: <1% November 2003	0.5% 2001, increasing to 4% Tier 1 and 2.5% Tier 1 or 2 by 2008	Yes

Pennsylvania

Choice Start Date	Rate Freeze/Default Service	POLR Service
January 1999	Rates Frozen from 2000 through 2010 (different end date depending on utility) Duquesne Light has already paid off stranded costs, market now open.	Yes – Local utilities responsible during their transition period – rules still being developed

Customer Participation (April 2004)

	Commercial	Industrial
Allegheny Power	.1%	0.0%
Duquesne Light	20.3%	39.4%
MetEd/Penelec	.1%	1.3%
PECO Energy	38.5%	4.5%
Penn Power	.1%	0.0%
PPL	1%	1.8%
UGI	0.1%	0.0%

RPS

For PECO, West Penn, and PP&L, 20% of residential customers served by competitive default provider: 2% in 2001, increasing 0.5% per year; for GPU, 0.2% in 2001 for 20% of customers, increasing to 80% in 2004.

Green Power Option

Yes

Washington DC

Choice Start Date	Rate Freeze/Default Service	POLR Service
January 2001	Rates capped from February 2001 through February 2005 (2007 for Low Income)	Yes – PEPCO is POLR until rate caps removed– then wholesale SOS model kicks in – large commercial will pay hourly market-based rates, all others will have fixed-price option
Customer Participation	**RPS**	**Green Power Option**
16.5% as of May 2003	Legislation introduced: 1.5% Tier 1 and 2.5% Tier 2 in 2006 increasing to 11% Tier 1 (no Tier 2) in 2021	Yes

Virginia

Choice Start Date	Rate Freeze/Default Service	POLR Service
January 2003 January 2004 for Kentucky Utilities and Co-ops/Munis	Rates Frozen from July 2001 to July 2010	Yes – local utility must supply at capped rates throughout the rate-freeze
Customer Participation	**RPS**	**Green Power Option**
	No	Yes

West Virginia

Choice Start Date	Rate Freeze/Default Service	POLR Service
Legislation passed in 2000 conditionally approving PSC's plan to deregulate, however, no new legislation actually allowing implementation	4 year rate freeze, 13 year phase-in proposed	
Customer Participation	**RPS**	**Green Power Option**
	No	No

Key Issues for PJM Area Customers

Common Denominators

- Competitive market with flexible transmission system in place – Competitive procurements undertaken by GSA, DESC, others.
- Market dominated by baseload coal/nuke plants now, CCCT plants will dominate pricing in the future.
- RPSs established
  - Require RPS of suppliers
  - Customer green power purchases count against supplier goal (if desired)
  - Supplier shortfalls result in added fees to customers (unless customer purchased green on own)
  - Customer can claim "green-ness" but can't resell if supplier claims
  - Solar power on-site requires REC to claim
  - Usually, small hydro, waste-to-energy, and biomass are "second class"

Delaware

- Rate caps coming off 2005-6
- RPS (if it passes) being implemented in 2006, fairly rapid ramp up (10% by 2018) given limited potential in area
- Agencies should be getting educated about price trends after 2005, supply options, impact of RPS, availability of public funds for efficiency and on-site renewables/DER.

Maryland

- Rate caps off or coming off
- RPS adopted expected to merge with PJM area trading system when it is in place
- POLR rates are market-based
- Agencies should be getting educated about impact of RPS, availability of public funds for efficiency and on-site renewables/DER.

New Jersey

- Rate caps are off, supplies being acquired competitively
- RPS in place
- POLR rates market based – hourly for largest customers
- Agencies should be getting educated about price trends after 2005, supply options, impact of RPS, availability of public funds for efficiency and on-site renewables/DER.

Pennsylvania

- Rate freeze off in part of state, supplies have been procured competitively (with mixed success, but it is a “success” story for deregulation)
- RPS in place
- POLR service is default
- Agencies should be getting educated about RPS options/changes, availability of public funds for efficiency and on-site renewables/DER.

Washington DC

- Rate freeze ends next Feb.
- RPS proposed
- POLR service is default
- Agencies should be getting educated about price trends, supply options, impact of RPS, availability of public funds for efficiency and on-site renewables/DER.

Virginia

- Rate freeze coming off in 2010?
- No RPS
- POLR service is default
- Rest on your laurels for negotiating a good rate early (if you are DOD anyway)

West Virginia

- Legislation passed approving deregulation plan, but with the caveat that ANOTHER legislative act is required to begin implementation…2nd legislative move has not occurred
- Sleep with one eye open?

Southeastern States

- Choice not a viable option anytime soon (legislation introduced in the Carolinas, but no action …. Other states still oppose. TVA will offer choice option in several years.)
- RPS? We don’t need no stinkin’ RPS!
- Sleep soundly!

Where Can You Get Help?

- FEMP Web Sites:
  - http://www.eere.energy.gov/femp/
  - http://pnnl-utilityrestructuring.pnl.gov
- Regional GSA office will aggregate customers
- So will DESC, especially DoD facilities
- FEMP can help through technical assistance with:
  - Goal setting and energy strategy development
  - Commodity procurement advice and support
  - On-site generation assessments
  - Efficiency projects
  - Renewable energy purchases and investments